Indiana Department of Environmental Management
Office of Air Quality

Appendix B – BACT Analysis
Addendum to the Technical Support Document (ATSD)
for a PSD/New Source Construction and Part 70 Operating Permit

Source Description and Location

Source Name:	**Riverview Energy Corporation**
Source Location:	**4702 E 2000 N, Dale, IN 47523**
County:	**Spencer**
SIC Code:	**2911 (Petroleum Refining), 2999 (Products of Petroleum and Coal, Not Elsewhere Classified)**
Operation Permit No.:	**T 147-39554-00065**
Permit Reviewer:	**Douglas Logan, P.E.**

Background Information

On January 25, 2018, the Office of Air Quality (OAQ) received an application from Riverview Energy Corporation related to the construction and operation of a new stationary direct coal hydrogenation plant.

This proposed plant will use a Veba Combi Cracker (VCC) process to produce premium distillate products, such as ultra-low sulfur diesel fuel. The VCC technology is a thermal hydrocracking/ hydrogenation process for converting raw coal at very high conversion rates and liquid yields into directly marketable distillates. The feedstock is slurried with finely ground coal, additive and catalyst and then is injected into the high pressure section of the process. After adding makeup hydrogen, the feed stream is preheated by heat recovery from the reactor effluents and fired heater. This feed mixture is converted in a cascade of three slurry phase reactors.

The converted coal, the additive and catalyst are separated from the vaporized reaction products and the recycle gas in a hot separator. The hot separator bottom product is fed to a vacuum flasher for additional distillate recovery. The hydrotreating stage is a single reactor vessel with three beds for hydrotreating, followed by two beds for hydrocracking to maximize diesel production. After leaving the hydrotreating stage the effluent is cooled, condensed and separated from the non-condensable gas fraction and the liquids are processed in a fractionator to produce high quality naphtha, ultra-low sulfur diesel fuel and fractionator bottoms. The bottoms are recycled back to the hydrotreating stage and converted to diesel.

Requirement for Best Available Control Technology (BACT)

326 IAC 2-2 requires a best available control technology (BACT) review to be performed on the proposed new emission units because the potential to emit of at least one pollutant is greater than the PSD major thresholds. The potential to emit of PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, VOC, CO, H_2SO_4, and GHGs is greater than PSD thresholds for these pollutants, therefore a BACT evaluation for these pollutants will be conducted.

Proposed New Emission Units

326 IAC 2-2 (Prevention of Significant Deterioration) requires a BACT analysis for the following emission units:

(a) Coal handling operations, identified as Block 1000, consisting of:

(1) One (1) shelter-type railcar dump unloading facility, identified as EU-1000, approved in 2019 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by a negative pressure enclosure and baghouse EU-1000, exhausting to stack EU-1000, consisting of:

(A) Two (2) enclosed receiving pits, identified as Receiving Pit 1 and Receiving Pit 2, discharging to Receiving Bin 1 and Receiving Bin 2, respectively.
(B) Two (2) enclosed receiving bins, identified as Receiving Bin 1 and Receiving Bin 2, discharging to Drag Flight Feeder 1 and Drag Flight Feeder 2, respectively, with water spray dust suppression systems.
(C) Two (2) enclosed drag flight feeders, identified as Drag Flight Feeder 1 and Drag Flight Feeder 2, discharging to the Unloading Conveyor, with water spray dust suppression systems.

Under the NSPS, 40 CFR 60, Subpart Y, EU-1000 is an affected facility.

(2) One (1) enclosed rail unloading conveyor discharging to Transfer Station 1, identified as Unloading Conveyor, approved in 2019 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

Under the NSPS, 40 CFR 60, Subpart Y, the Unloading Conveyor is an affected facility.

(3) One (1) enclosed transfer station discharging to Conveyor 1, Conveyor 2, or Conveyor 9, identified as Transfer Station 1 (EU-1001), approved in 2019 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1001, exhausting to stack EU-1001.

Under the NSPS, 40 CFR 60, Subpart Y, Transfer Station 1 (EU-1001) is an affected facility.

(4) One (1) enclosed feed conveyor discharging to Stacker 1 Boom Conveyor/Chute, identified as Conveyor 1, approved in 2019 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 1 is an affected facility.

(5) One (1) enclosed stacker boom conveyor/chute discharging to Coal Stockpiles #1A & #1B, identified as Stacker 1 Boom Conveyor/Chute, approved in 2019 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Stacker 1 Conveyor/Chute is an affected facility.

(6) Two (2) radial conical ring coal storage piles, approved in 2019 for construction, identified as Stockpile #1A and Stockpile #1B, with a maximum capacity of

93,000 tons, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Stockpiles #1A and #1B are affected facilities.

(7) One (1) enclosed feed conveyor discharging to Stacker 2 Boom Conveyor/Chute, identified as Conveyor 2, approved in 2019 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 2 is an affected facility.

(8) One (1) enclosed stacker boom conveyor/chute discharging to Coal Stockpiles #2A & #2B, identified as Stacker 2 Boom Conveyor/Chute, approved in 2019 for construction, with a maximum capacity of 5,000 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Stacker 2 Boom Conveyor/Chute is an affected facility.

(9) Two (2) radial conical ring coal storage piles, approved in 2019 for construction, identified as Stockpile #2A and Stockpile #2B, with a maximum capacity of 93,000 tons, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Stockpiles #2A and #2B are affected facilities.

(10) One (1) reclaimer for Stockpiles #1A & #1B, discharging to Reclaim Conveyor 6, identified as Reclaimer 1, approved in 2019 for construction, with a maximum capacity of 500 tons of coal per hour, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Reclaimer 1 is an affected facility.

(11) One (1) enclosed reclaimer conveyor, identified as Conveyor 6 discharging to the Reclaim Transfer Station, approved in 2019 for construction, with a maximum capacity of 500 tons of coal per hour, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 6 is an affected facility.

(12) One (1) reclaimer for Stockpiles #2A & #2B, discharging to Reclaim Conveyor 7, identified as Reclaimer 2, approved in 2019 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by the coal storage pile enclosure and baghouse EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Reclaimer 2 is an affected facility.

(13) One (1) enclosed reclaimer conveyor, identified as Conveyor 7 discharging to the Reclaim Transfer Station, approved in 2019 for construction, with a maximum

capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 7 is an affected facility.

(14) One (1) enclosed transfer station conveyor, identified as Conveyor 9 discharging to the Reclaim Transfer Station, approved in 2019 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 9 is an affected facility.

(15) One (1) enclosed reclaim transfer station discharging to Reclaim Conveyor 8, identified as Reclaim Transfer Station (EU-1006), approved in 2019 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, with particulate emissions controlled by baghouse EU-1006, exhausting to stack EU-1006.

Under the NSPS, 40 CFR 60, Subpart Y, the Reclaim Transfer Station is an affected facility.

(16) One (1) enclosed conveyor, identified as Reclaim Conveyor 8 discharging to the Coal Mill and Pulverizer, approved in 2019 for construction, with a maximum capacity of 500 tons of coal per hour, with particulate emissions controlled the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, Conveyor 8 is an affected facility.

(b) Coal drying loop, collectively identified as EU-1008, with emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008, consisting of the following:

(1) One (1) enclosed coal mill and pulverizer, identified as Coal Mill and Pulverizer, approved in 2019 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer, with particulate emissions controlled the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Mill and Pulverizer is an affected facility.

(2) One (1) enclosed coal dryer, identified as Coal Dryer, approved in 2019 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Coal Dryer Baghouse, with particulate emissions controlled by the Coal Dryer Baghouse.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer is an affected facility.

(3) One (1) natural gas and process fuel gas-fired heater, identified as Coal Dryer Heater EU-1007, approved in 2019 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 55.8 MMBtu/hr (HHV), with emissions exhausting to Stack EU-1007.

Under the NSPS, 40 CFR 60, Subpart Ja, the Coal Dryer Heater (EU-1007) is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Heater (EU-1007) is part of an affected thermal dryer.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, the Coal Dryer Heater (EU-1007) is an affected source.

(4) One (1) process baghouse, identified as Coal Dryer Baghouse, approved in 2019 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging fines to the Block 2000 Coal Hopper, exhausting particulate and filtered nitrogen to the condenser.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Dryer Baghouse is an affected facility.

(5) One (1) water-cooled condenser, identified as Drying Loop Condenser, approved in 2019 for construction, with a nominal capacity of 40 MMBtu/hr, with particulate emissions controlled by Loop Purge Baghouse EU-1008 exhausting to stack EU-1008.

Under the NSPS, 40 CFR 60, Subpart Y, the Drying Loop Condenser is part of an affected thermal dryer.

(c) Additives handling operations, identified as Block 1500, consisting of:

(1) Three (3) pneumatic (nitrogen) truck unloading systems discharging to storage silos, approved in 2019 for construction, as follows:

(A) Coarse Additive Unloading, with a maximum capacity of 20.00 tons per hour.
(B) Fine Additive Unloading, with a maximum capacity of 20.00 tons per hour.
(C) Sodium Sulfide (Na_2S) Unloading, with a maximum capacity of 10.00 tons per hour.

(2) Three (3) nitrogen-blanketed storage silos, as follows:

(A) One (1) coarse additive silo, identified as T34, approved in 2019 for construction, controlled by baghouse EU-1501, exhausting to stack EU-1501.
(B) One (1) fine additive silo, identified as T33, approved in 2019 for construction, controlled by baghouse EU-1502, exhausting to stack EU-1502.
(C) One (1) Na_2S silo, identified as T35, approved in 2019 for construction, controlled by baghouse EU-1503, exhausting to stack EU-1503.

(3) One (1) nitrogen-blanketed fine additive production system, identified as Fine Additive Production System, approved in 2019 for construction, with a maximum capacity of 3.28 tons per hour, controlled by baghouse EU-1504, exhausting to stack EU-1504, consisting of:

(A) One (1) coarse additive silo rotary feeder solid weigh scale.
(B) One (1) coarse additive screw conveyor discharging to the Fine Additive Production System.

(C) One (1) additive size reduction system, identified as Fine Additive Production System discharging to the T33 or the Block 2000 coarse additive transfer system.

(d) VEBA Combi Cracker (VCC) unit operations, identified as Block 2000, consisting of:

(1) One (1) enclosed hopper receiving coal from Block 1000 Coal Dryer Baghouse and discharging to the Feed Prep Screw Conveyor, identified as Coal Hopper, approved in 2019 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year.

Under the NSPS, 40 CFR 60, Subpart Y, the Coal Hopper is an affected facility.

(2) One (1) enclosed screw conveyor, identified as Closed Screw Conveyor, approved in 2019 for construction, with a maximum capacity of 500 tons of coal per hour and a bottlenecked capacity of 2,263,248 tons per year, discharging to the Feed Premix Drum, identified as Closed Screw Conveyor, with particulate emissions controlled by the Coal Handling System Filter, exhausting to stack EU-2005.

Under the NSPS, 40 CFR 60, Subpart Y, the Closed Screw Conveyor is an affected facility.

(3) One (1) nitrogen-blanketed coarse additive transfer system, identified as Coarse Additive Screw Conveyor, approved in 2019 for construction, with a maximum capacity of 2.20 tons per hour, receiving material from the Block 1500 coarse additive silo and discharging to the Feed Premix Drum, with particulate emissions controlled by the Coarse Additive System Filter, exhausting to stack EU-2006.

(4) One (1) nitrogen-blanketed fine additive transfer system, identified as Fine Additive Handling System, approved in 2019 for construction, with a maximum capacity of 3.28 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Fine Additive System Filter, exhausting to stack EU-2007, consisting of:

(A) One (1) fine additive silo rotary feeder solid weigh scale.
(B) One (1) fine additive screw conveyor discharging to the Block 2000 feed premix drum.

(5) One (1) nitrogen-blanketed Na_2S slurry preparation system, identified as Na_2S Slurry Preparation, approved in 2019 for construction, with a maximum capacity of 0.077 tons per hour, discharging to the Block 2000 feed premix drum, with particulate emissions controlled by the Na_2S Handling System Filter, exhausting to stack EU-2008, consisting of:

(A) One (1) Na_2S silo rotary feeder solid weigh scale.
(B) One (1) Na_2S screw conveyor discharging to the Na_2S mixing drum.
(C) One (1) nitrogen-blanketed mixing drum for Na_2S and Block 2000 vacuum tower VGO (vacuum gas oil) discharging to the feed premix drum.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the mixing drum is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the mixing drum is an affected source.

(6) One (1) feed premix drum, identified as Feed Premix Drum, approved in 2019 for construction, receiving coal, solid additives, and recycled vacuum gas oil (VGO) and discharging to the feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the feed premix drum is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed premix drum is part of an affected source.

(7) One (1) natural gas and process fuel gas-fired indirect feed heater, identified as EU-2001, approved in 2019 for construction, equipped with Low-NOX burners, with a maximum heat input capacity of 128.4 MMBtu/hr (HHV), discharging to the 1st stage reactors, exhausting to stack EU-2001.

Under the NSPS, 40 CFR 60, Subpart Ja, the feed heater EU-2001 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the feed heater EU-2001 is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the feed heater EU-2001 is part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, feed heater EU-2001 is an affected source.

(8) One (1) natural gas and process fuel gas-fired indirect treat gas heater, identified as EU-2002, approved in 2019 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 52.8 MMBtu/hr (HHV), receiving hydrogen from Block 7000 and discharging to the 1st stage reactors, exhausting to stack EU-2002.

Under the NSPS, 40 CFR 60, Subpart Ja, the treat gas heater EU-2002 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, treat gas heater EU-2002 is an affected source.

(9) One (1) first stage reactor - liquid phase hydrocracking system, identified as LPH, approved in 2019 for construction, discharging to the hot separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the first stage reactor - liquid phase hydrocracking system is part of an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the first stage reactor - liquid phase hydrocracking system is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the first stage reactor - liquid phase hydrocracking system is part of an affected source.

(10) One (1) hot separator, identified as Hot Separator, approved in 2019 for construction, discharging vapor to the 2nd stage reactors and liquids to the vacuum column feed heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the hot separator is part of an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the hot separator is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the hot separator is part of an affected source.

(11) One (1) natural gas and process fuel gas-fired indirect vacuum column feed heater, identified as EU-2003, approved in 2019 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 9 MMBtu/hr (HHV), discharging to the vacuum distillation tower, exhausting to stack EU-2003.

Under the NSPS, 40 CFR 60, Subpart Ja, the vacuum column feed heater EU-2003 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the vacuum column feed heater EU-2003 is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum column feed heater EU-2003 is part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, vacuum column feed heater EU-2003 is an affected source.

(12) One (1) vacuum distillation tower, identified as Vacuum Distillation Column, approved in 2019 for construction, discharging sour LPG to the amine absorber, vapor to the 2nd stage reactors, slop oil to Block 4000, phenolic sour water to Block 3000, and hydrogenated residue to Block 5000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the vacuum distillation tower is part of an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the vacuum distillation tower is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the vacuum distillation tower is part of an affected source.

(13) One (1) second stage reactor - gas phase hydrotreating system, identified as GPH, approved in 2019 for construction, discharging to the cold separator, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the second stage reactor - gas phase hydrotreating system is part of an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the second stage reactor - gas phase hydrotreating system is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the second stage reactor - gas phase hydrotreating system is part of an affected source.

(14) One (1) cold separator, identified as Cold Separator, approved in 2019 for construction, discharging non-phenolic sour water to Block 3000 and hydrocarbons to the fractionator heater, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the cold separator is part of an affected facility.

Under the NSPS, 40 CFR 60, Subpart RRR, the cold separator is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the cold separator is part of an affected source.

(15) One (1) natural gas and process fuel gas-fired indirect fractionator heater, identified as EU-2004, approved in 2019 for construction, equipped with Low-NO_X burners, discharging to the fractionator tower, with a maximum heat input capacity of 156 MMBtu/hr (HHV), exhausting to stack EU-2004.

Under the NSPS, 40 CFR 60, Subpart Db, fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, the fractionator heater EU-2004 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the fractionator heater is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator heater is part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, fractionator heater EU-2004 is an affected source.

(16) One (1) fractionator tower, identified as Fractionator Tower, approved in 2019 for construction, discharging sour LPG to the amine absorber, naphtha and diesel fuel to Block 4000, vacuum gas oil (VGO) to Block 4000 or the Feed Premix

Drum, and non-phenolic sour water to Block 3000, with emergency and pressure relief streams vented to the Block 4000 high pressure flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the fractionator tower is part of an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the fractionator tower is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the fractionator tower is part of an affected source.

(17) One (1) amine absorber system discharging sweet LPG to Block 4000 and rich amine to Block 3000, consisting of:

(A) One (1) two-stage high pressure absorber, identified as HP Absorber, approved in 2019 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to the low pressure absorber and rich amine to the amine regeneration unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) two-stage low pressure absorber, approved in 2019 for construction, where acid gas from Block 2000 contacts amine solution followed by water wash discharging treated gas to Block 4000 and rich amine to the amine regeneration unit or rich amine surge tank, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the HP Absorber and LP Absorber are part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the HP Absorber and LP Absorber is part of an affected facility.

Under the NSPS, 40 CFR 60, Subpart NNN, the amine absorber system is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the HP Absorber and LP Absorber are part of an affected source.

(18) Block 2000 petroleum refinery process unit heat exchangers that are in organic HAP service, as defined in 40 CFR 63, Subpart CC, and all water lines to and from these petroleum refinery process unit heat exchangers.

Under the NESHAP, 40 CFR 63, Subpart CC, petroleum refinery process unit heat exchangers that are in organic HAP service and related water lines are part of an affected source.

(e) Sulfur recovery operations, identified as Block 3000, consisting of:

(1) Amine Regeneration Unit, consisting of:

(A) One (1) heat exchanger, identified as Rich Amine-Lean Amine Heat Exchanger, approved in 2019 for construction, where rich amine from Block 2000 or the rich amine surge tank is heated by lean amine discharging rich amine to the stripper and lean amine to storage or the Block 2000 absorbers, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) stripper column , identified as Stripper, approved in 2019 for construction, discharging lean amine to the Rich Amine-Lean Amine Heat Exchanger and the reboiler and vapor to the overheads condenser, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(C) One (1) water-cooled condenser, identified as Overheads Condenser, approved in 2019 for construction, discharging condensate to the stripper condenser accumulator, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(D) One (1) accumulator drum, identified as Stripper Condenser Accumulator, approved in 2019 for construction, discharging condensate to stripper reflux and the sour water stripping system and hydrogen sulfide gas to the Sulfur Recovery System, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(E) One (1) steam-heated reboiler, identified as Stripper Reboiler, approved in 2019 for construction, discharging lean amine to the stripper reflux, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Amine Regeneration Unit is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the Amine Regeneration Unit is part of a sulfur recovery plant that is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the Amine Regeneration Unit is part of an affected source.

(2) Sour Water Stripping System, consisting of:

(A) One (1) sour water stripping system, identified as Phenolic Sour Water Stripping System, approved in 2019 for construction, discharging acid gas to the sulfur recovery system, receiving sour water from the Block 2000 vacuum distillation column, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(B) One (1) sour water stripping system, identified as Non-Phenolic Sour Water Stripping System, approved in 2019 for construction, discharging acid gas to the sulfur recovery, receiving sour water from the Block 2000 cold separator, condensate from the amine regeneration unit stripper condensate accumulator, and sour water from the sulfur recovery system, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

Under the NSPS, 40 CFR 60, Subpart Ja, the Sour Water Stripping System is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the Sour Water Stripping System is part of a sulfur recovery plant that is part of an affected facility.

Under the NESHAP, 40 CFR 61, Subpart FF, provisions of the subpart are applicable to the Sour Water Stripping System.

Under the NESHAP, 40 CFR 63, Subpart CC, the Sour Water Stripping System is part of an affected source.

(3) Sulfur Recovery System, consisting of:

(A) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit A, approved in 2019 for construction, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602A burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.

(ii) One (1) acid gas furnace, identified as A-602A Furnace, discharging to the waste heat boiler.

(iii) One (1) waste heat boiler identified as A-602A Waste Heat Boiler, using heat from A-602A Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.

(iv) One (1) three-stage Claus reactor train, identified as SRU A reactors, discharging treated gas to the TGTU A Heat Exchanger and molten sulfur to the sulfur product pit.

(v) One (1) sulfur product pit, identified as Sulfur Product Pit A, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.

(vi) One (1) heat exchanger, identified as TGTU A Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.

(vii) One (1) hydrogenation reactor, identified as R-604A, discharging tail gas to the quench contactor.

(viii) One (1) quench contactor, identified as T-601A, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.

(ix) One (1) amine absorber, identified as T-602A, discharging tail gas to the incinerator and rich amine to the amine regeneration unit.

(x) One (1) incinerator, identified as A-605A Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605A Waste Heat Boiler, using heat from A-605A Incinerator to create high pressure steam, exhausting to stack TGTUA.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605A Incinerator and A-605A Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit A is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with Sulfur Recovery Unit A is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit A is part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit A is an affected source.

(B) One (1) sulfur recovery unit, identified as Sulfur Recovery Unit B, approved in 2019 for construction, with emergency and pressure relief streams vented to the Block 4000 sulfur flare.

(i) One (1) burner, identified as A-602B burner, combusting acid gas from the amine regeneration unit and the phenolic and non-phenolic sour water strippers and using natural gas and process fuel gas for start-up, equipped with Low-NOX burners, with a heat input capacity of 40.00 MMBtu/hr (HHV), discharging to the acid gas furnace.
(ii) One (1) acid gas furnace, identified as A-602B Furnace, discharging to the waste heat boiler.
(iii) One (1) waste heat boiler identified as A-602B Waste Heat Boiler, using heat from A-602B Furnace to create high pressure steam and discharging cooled gas to the Claus reactors.
(iv) One (1) three-stage Claus reactor train, identified as SRU B reactors, discharging treated gas to the TGTU B Heat Exchanger and molten sulfur to the sulfur product pit.
(v) One (1) sulfur product pit, identified as Sulfur Product Pit B, with a maximum throughput capacity of 44,611 tons of sulfur per year (70% of VCC capacity) and a nominal capacity 31,865 tons per year (50% of VCC capacity), discharging purge air to the TGTU incinerator and molten sulfur to Block 4000.
(vi) One (1) heat exchanger, identified as TGTU B Heat Exchanger, discharging tail gas and hydrogen to the hydrogenation reactor.
(vii) One (1) hydrogenation reactor, identified as R-604B, discharging tail gas to the quench contactor.
(viii) One (1) quench contactor, identified as T-601B, discharging tail gas to the amine absorber and sour water to the non-phenolic sour water stripping system.
(ix) One (1) amine absorber, identified as T-602B, discharging tail gas to the incinerator and rich amine to the amine regeneration unit.

(x) One (1) incinerator, identified as A-605B Incinerator, combusting tail gas and natural gas and process fuel gas, with a maximum heat input capacity of 52.75 MMBtu/hr (0.60 MMBtu/hr from tail gas) (HHV) and a normal heat input capacity of 37.68 MMBtu/hr (0.43 MMBtu/hr from tail gas) (HHV), exhausting to a waste heat boiler.

(xi) One (1) waste heat boiler identified as A-605B Waste Heat Boiler, using heat from A-605B Incinerator to create high pressure steam, exhausting to stack TGTUB.

Under the NSPS, 40 CFR 60, Subpart Dc, the A-605B Incinerator and A-605B Waste Heat Boiler is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, Sulfur Recovery Unit B is part of a sulfur recovery plant that is an affected facility.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with Sulfur Recovery Unit B is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Sulfur Recovery Unit B is part of an affected source.

Under the NESHAP, 40 CFR 63, Subpart UUU, each process vent or group of process vents and each bypass line serving Sulfur Recovery Unit B is an affected source.

(4) Block 3000 petroleum refinery process unit heat exchangers that are in organic HAP service, as defined in 40 CFR 63, Subpart CC, and all water lines to and from these petroleum refinery process unit heat exchangers.

Under the NESHAP, 40 CFR 63, Subpart CC, petroleum refinery process unit heat exchangers that are in organic HAP service and related water lines are part of an affected source.

(f) Offsites operations, identified as Block 4000, consisting of:

(1) Flares, as follows:

(A) One (1) natural gas and process fuel gas-fired flare identified as High Pressure (HP) Flare, approved in 2019 for construction, servicing overpressure and emergency reliefs from Block 2000 VEBA Combi Cracker operations, controlling emissions from Block 2000 depressurization system, with pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(B) One (1) natural gas and process fuel gas-fired flare, identified as Low Pressure (LP) Flare, approved in 2019 for construction, servicing overpressure reliefs from Block 7000 Hydrogen Unit operations, controlling emissions from Block 7000 start-up and shut-down vents, and a continuous sweep stream from the Block 2000 slop tank, with a sweep and pilot heat input capacity of 6.50 MMBtu/hr (LHV), exhausting to the atmosphere.

(C) One (1) natural gas and process fuel gas-fired flare, identified as Sulfur Block Flare, approved in 2019 for construction, servicing overpressure reliefs from Block 3000 Sulfur Recovery operations and sulfur loading, controlling emergency streams from Sulfur Recovery Units A and B, and a continuous sweep stream from the sour water storage tanks, with a sweep and pilot heat input capacity of 0.77 MMBtu/hr (LHV), exhausting to the atmosphere.

(D) One (1) natural gas and process fuel gas-fired flare, identified as Loading Flare, approved in 2019 for construction, servicing Block 4000 naphtha, diesel, and ammonia loading operations, with a pilot heat input capacity of 0.20 MMBtu/hr (LHV), exhausting to the atmosphere.

Under the NSPS, 40 CFR 60, Subpart Ja, the flares are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the flares is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, the HP Flare, LP Flare, and SB Flare are control devices for emission points subject to this subpart.

(2) Product storage tanks, approved in 2019 for construction, as follows:

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T1	IFR	Naphtha product	4,629,879 (17,524)	-
T2	IFR	Naphtha product	4,629,879 (17,524)	-
T3	FR	Diesel product	4,525,796 (17,130)	-
T4	FR	Diesel product	4,525,796 (17,130)	-
T5	FR	Diesel product	4,525,796 (17,130)	-
T6	IFR	Naphtha or diesel product	4,629,879 (17,524)	-
T7	FR	Molten sulfur	342,367 (1,296)	-
T8	FR	Molten sulfur	342,367 (1,296)	-
T9	HPV	Ammonia product	36,720 (17,524)	-
T10	FR	Residue surge tank 1	926,980 (17,524)	-
T11	FR	Residue surge tank 2	926,980 (3,509)	-
T12	FR	Residue feed tank	926,980 (3,509)	-
T13	FR	VGO tank 1	926,980 (3,509)	-
T14	FR	VGO tank 2	926,980 (3,509)	-

ID	Construction[1]	Contents	Capacity (gallons) (m^3)	Control[2]
T15	HPV	LPG storage	48,872 (185)	-
T16	FR	Slop tank	4,195,581 (15,880)	LP flare
T17	FR	Diesel fuel tank	23,775 (90)	-
T18	FR	Non-phenolic sour water storage tank 1	1,268,026 (4,799)	SB flare
T19	FR	Non-phenolic sour water storage tank 2	1,268,026 (4,799)	SB flare
T20	FR	Non-phenolic sour water storage tank 3	1,268,026 (4,799)	SB flare
T21	FR	Phenolic sour water storage tank	40,947 (155)	SB flare
T22	FR	Stripped non-phenolic sour water surge tank	1,268,026 (4,799)	-
T23	FR	Stripped phenolic sour water surge tank	13,737 (52)	-
T24	FR	Amine surge/deinventory tank	63,943 (242)	-
T25	FR	Fresh amine tank	63,943 (242)	-
T26	FR	Amine containment tank (sump)	793 (3)	-

1. *FR - fixed roof, IFR - internal floating roof, HPV-horizontal pressure vessel*
2. *Tank vents to flares are part of sweep and pilot gas streams.*

Under the NSPS, 40 CFR 60, Subpart Kb, T1, T2, and T6 are affected facilities.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with T1 - T6 and T10 - T15 is part of an affected facility.

Under the NSPS, 40 CFR 60, Subpart QQQ, T16 is part of an affected facility.

Under the NSPS, 40 CFR 61, Subpart FF, provisions of the subpart are applicable to T16 and T18 - T21.

Under the NESHAP, 40 CFR 63, Subpart CC, T1 - T6, T10 - T14, T16, and T18-T23 are part of an affected source.

Provisions of the NESHAP, 40 CFR 63, Subpart WW, apply to T3 - T6 and T10 - T14.

(3) Loading operations, as follows:

(A) One (1) 8-spot railcar loading rack for naphtha and diesel, identified as Product Loading Rack, approved in 2019 for construction, with a maximum capacity of 2,500 gallons per minute at each spot, controlled by the Loading Flare.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with the Product Loading Rack is part of an affected facility.

Under the NESHAP, 40 CFR 61, Subpart BB, the Product Loading Rack is an affected facility.

(B) One (1) single-spot railcar loading rack for ammonia, identified as Ammonia Loading Rack, approved in 2019 for construction, with a bottlenecked capacity of 15,024,167 gallons per year, controlled by the Loading Flare.

(C) One (1) single-spot railcar loading rack for molten sulfur, identified as Sulfur Loading Rack, approved in 2019 for construction, with a bottlenecked capacity of 63,781 tons per year, controlled by the Sulfur Block Flare.

(g) Residue solidification operations, identified as Block 5000, as follows:

(1) Four (4) pastillators, identified as EU-5001A - EU5001D, approved in 2019 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5001.

(2) Four (4) pastillators, identified as EU-5002A - EU5002D, approved in 2019 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5002.

(3) Four (4) pastillators, identified as EU-5003A - EU5003D, approved in 2019 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5003.

(4) Four (4) pastillators, identified as EU-5004A - EU5004D, approved in 2019 for construction, with a maximum capacity of 4.29 tons per hour, each, exhausting to stack EU-5004.

(5) Enclosed conveyors for residue pellets, with particulate emissions controlled by filters EU-5009, EU-5010, and EU-5011, as follows:

(A) One (1) enclosed conveyor, identified as Block 1 & 2 transfer conveyors, with a maximum capacity of 34.33 tons per hour, receiving pastillators from the eight (8) pastillators, identified as EU-5001A - EU5001D and EU-5002A - EU5002D.

(B) One (1) enclosed conveyor, identified as Block 3 & 4 transfer conveyors, with a maximum capacity of 34.33 tons per hour, receiving pastillators from the eight (8) pastillators, identified as EU-5003A - EU5003D and EU-5004A - EU5004D.

(C) One (1) enclosed loading conveyor, identified as Loading Conveyor, approved in 2019 for construction, with a maximum capacity of 51.49 tons per hour, receiving pastillators from Block 1 & 2 and Block 3 & 4 transfer conveyors, and discharging to the bulk container loading station, railcar residue silo, or swing residue silo.

(6) One (1) residue bulk container loading station, identified as EU-5009, approved in 2019 for construction, with a maximum capacity of 8.00 tons per hour, using filter EU-5009 for particulate control and exhausting to stack EU-5009.

(7) One (1) railcar residue storage silo, identified as EU-5010, approved in 2019 for construction, with a maximum capacity of 1,236 tons per day, using baghouse EU-5010 for particulate control and exhausting to stack EU-5010.

(8) Two (2) residue loading hoppers, identified as EU-5005 and EU-5006, approved in 2019 for construction, with a combined maximum capacity of 1,236 tons per day, receiving residue from the railcar residue storage silo, using baghouse EU-5010 for particulate control and exhausting to stack EU-5010.

(9) One (1) swing residue storage silo, identified as EU-5011, approved in 2019 for construction, with a maximum capacity of 1,236 tons per day, using baghouse EU-5011 for particulate control and exhausting to stack EU-5011.

(10) Two (2) residue loading hoppers, identified as EU-5007 and EU-5008, approved in 2019 for construction, with a combined maximum capacity of 1,236 tons per day, receiving residue from the swing residue storage silo, using baghouse EU-5011 for particulate control and exhausting to stack EU-5011.

(11) Residue loadout operations using spouts and choke flow-practices, as follows:

(A) Two (2) railcar loadspots, approved in 2019 for construction.

(B) Two (2) swing loadspots, approved in 2019 for construction, accommodating either trucks or railcars.

(h) Utilities operations, identified as Block 6000, consisting of:

(1) One (1) natural gas and process fuel gas-fired package boiler, identified as EU-6000, approved in 2019 for construction, equipped with Low-NO_X burners, with a maximum heat input capacity of 68.50 MMBtu/hr (HHV), exhausting to stack EU-6000.

Under the NSPS, 40 CFR 60, Subpart Dc, boiler EU-6000 is an affected facility.

Under the NSPS, 40 CFR 60, Subpart Ja, boiler EU-6000 is an affected facility.

Under the NESHAP, 40 CFR 63, Subpart DDDDD, boiler EU-6000 is an affected source.

(2) One (1) three-cell crossflow mechanical draft cooling tower, identified as EU-6001, approved in 2019 for construction, with a maximum capacity of 32,000 gallons per hour, equipped with mist eliminators and exhausting to stacks EU-6001, EU-6002, and EU-6003.

Under the NESHAP, 40 CFR 63, Subpart CC, the three-cell cooling tower is part of an affected source.

(3) One (1) diesel engine-driven emergency generator, identified as EU-6006, approved in 2019 for construction, with a maximum heat input capacity of 19.60 MMBtu/hr (2,800 hp) (average heating value), exhausting to stack EU-6006.

Under the NSPS, 40 CFR 60, Subpart IIII, provisions of the subpart are applicable to emergency generator EU-6006.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency generator EU-6006 is an affected source.

(4) One (1) diesel engine-driven emergency fire pump, identified as EU-6008, approved in 2019 for construction, with a maximum heat input capacity of 5.25 MMBtu/hr (750 hp) (average heating value), exhausting to stack EU-6008.

Under the NSPS, 40 CFR 60, Subpart IIII, provisions of the subpart are applicable to emergency fire pump EU-6008.

Under the NESHAP, 40 CFR 63, Subpart ZZZZ, emergency fire pump EU-6008 is an affected source.

(i) Water supply and treatment operations, identified as Block 6500, consisting of:

(1) One (1) pneumatic lime truck unloading system, identified as Lime Unloading, approved in 2019 for construction, with a maximum capacity of 20.00 tons per hour, discharging to silo EU-6501.

(2) One (1) lime storage silo, identified as EU-6501, approved in 2019 for construction, with a maximum capacity of 20.00 tons per hour, with particulate emissions controlled by dust collector EU-6501 and exhausting to stack EU-6501.

(j) Hydrogen unit operations, identified as Block 7000, as follows:

(1) Hydrogen Plant 1, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7003, identified as Feed Water Treatment System 1, approved in 2019 for construction, exhausting to stack EU-7003.

(B) One (1) feed preparation train, identified as Feed Prep 1, approved in 2019 for construction, consisting of:

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7001, approved in 2019 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7001, is an affected facility.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2019 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 1, approved in 2019 for construction, discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 1, approved in 2019 for construction, discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with Hydrogen Plant 1 is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 1 is part of an affected source.

(2) Hydrogen Plant 2, with a maximum capacity of 105 million standard cubic feet (scf) (279 tons) of hydrogen per day, consisting of:

(A) One (1) boiler feed water treatment system including deaerator vent EU-7004, identified as Feed Water Treatment System 2, approved in 2019 for construction, exhausting to stack EU-7004.

(B) One (1) feed preparation train, identified as Feed Prep 2, approved in 2019 for construction, consisting of:

(i) One (1) hydrogenation reactor.
(ii) One (1) hydrogen sulfide adsorber.

(C) One (1) reformer system, consisting of:

(i) One (1) steam-hydrocarbon reformer furnace fired with process fuel gas and PSA tail gas supplemented by pipeline natural gas, identified as EU-7002, approved in 2019 for construction, with a maximum heat input capacity of 838.6 MMBtu/hr (HHV), using selective catalytic reduction for NOx control, discharging water gas to the CO-shift converter, exhausting combustion products to the waste heat recovery system.

Under the NSPS, 40 CFR 60, Subpart Ja, steam-hydrogen reformer, EU-7002, is an affected facility.

(ii) One (1) heat recovery system generating high pressure steam, incorporated in the reformer furnace convection section via heat recovery coils, approved in 2019 for construction.

(D) One (1) catalytic CO-shift converter, identified as CO-shift Converter 2, approved in 2019 for construction, discharging shift gas to the pressure swing adsorber.

(E) One (1) pressure swing adsorber, identified as PSA 2, approved in 2019 for construction, discharging hydrogen to feed preparation and Block 2000 and tail gas to the reformer as fuel.

Under the NSPS, 40 CFR 60, Subpart GGGa, the group of all the equipment (defined in § 60.591a) associated with Hydrogen Plant 2 is part of an affected facility.

Under the NESHAP, 40 CFR 63, Subpart CC, Hydrogen Plant 2 is part of an affected source.

(3) Block 7000 petroleum refinery process unit heat exchangers that are in organic HAP service, as defined in 40 CFR 63, Subpart CC, and all water lines to and from these petroleum refinery process unit heat exchangers.

Under the NESHAP, 40 CFR 63, Subpart CC, petroleum refinery process unit heat exchangers that are in organic HAP service and related water lines are part of an affected source.

(k) Wastewater treatment operations, identified as Block 8000, as follows:

(1) One (1) wastewater junction box with associated process drains, identified as Oily Water Sump, approved in 2019 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8002.

(2) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Water Separator, approved in 2019 for construction, discharging oil to the Slop Tank (T16) and water to MH1.

(3) One (1) wastewater junction box with, identified as MH1, approved in 2019 for constructions, with emissions controlled by a carbon canister, exhausting to stack EU-8003.

(4) One (1) totally enclosed oil-water separator with associated process drains, identified as Oily Amine Separator, approved in 2019 for construction, discharging oil to the Slop Tank (T16) and amine solution to the Rich Amine Return Header.

(5) One (1) biological wastewater treatment system, approved in 2019 for construction, with emissions exhausting to vent EU-8001.

Under the NSPS, 40 CFR 60, Subpart QQQ, the process drains, junction boxes, Oily Water Separator, Oily Amine Separator, associated sewer lines, and any secondary oil-water separator in the biological wastewater treatment system are an affected aggregate facility.

Under the NESHAP, 40 CFR 61, Subpart FF, provisions of the subpart are applicable to the Oily Water Separator, Oily Amine Separator, and any secondary oil-water separator in the biological wastewater treatment system.

Under the NESHAP, 40 CFR 63, Subpart CC, the wastewater streams and treatment operations associated with petroleum refining process units are part of a new affected source..

Summary of the Best Available Control Technology (BACT) Process

IDEM, OAQ conducts BACT analyses in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, which outlines the steps for conducting a top-down BACT analysis. Those steps are listed below:

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls and document the results; and
(5) Select BACT.

Also in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, BACT analyses take into account the energy, environmental, and economic impacts of the control options. Emission reductions may be determined through the application of available control techniques, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause adverse environmental effects to public health and the environment.
The Office of Air Quality (OAQ) makes BACT determinations by following the five steps identified above.

This BACT determination is based on the following information:

(1) The EPA RACT/BACT/LAER (RBLC) Clearinghouse;
(2) EPA and State air quality permits;
(3) Communications with control device equipment manufacturers;
(4) Technical books and articles; and
(5) Guidance documents from state and federal agencies.

Particulate (PM, PM_{10} and $PM_{2.5}$) BACT Analysis
Material Handling

<u>Step 1: Identify Potential Control Technologies</u>

Particulate matter (PM) is a complex mixture of small particles and liquid droplets. PM can be made up of a variety of components, including acids, organic chemicals, metals, and soil or dust particles. PM includes any size of filterable particulate. Filterable particulate is the particulate that is emitted directly as a solid or liquid at the stack.

Emissions of particulate matter (PM) are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere. In cases where the material being emitted is organic, particulate matter may be controlled through a combustion process. Generally, PM emissions are controlled through one of the following mechanisms:

(1) Mechanical collectors (such as cyclones or multiclones).
(2) Wet scrubbers.
(3) Electrostatic precipitators (ESP).
(4) Fabric filter dust collectors (baghouses).
(5) Wet suppression

Fugitive PM emissions from paved roads are typically controlled through the use of work practices which include a site-specific Fugitive Dust Control Plan.

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Mechanical Collectors (such as Cyclones or Multiclones)

Mechanical collectors use the inertia of the particles for collection. The particulate-laden gas stream enters the control device and is forced to move in a cyclonic manner, which causes the particles to move toward the outside of the vortex. Most of the large-diameter particles enter a hopper below the cyclonic tubes while the gas stream turns and exits the device.

Cyclones are typically used to remove relatively large particles from gas streams. Conventional single cyclones are estimated to control PM at 70-90%, PM_{10} at 30-90%, and $PM_{2.5}$ at 0-40%. High efficiency single cyclones are designed to achieve higher control of smaller particles and multiclones may also achieve higher control of smaller particles. Collection efficiency generally increases with particle size and/or density, inlet duct velocity, cyclone body length, number of gas revolutions in the cyclone, ratio of cyclone body diameter to gas exit diameter, dust loading, and smoothness of the cyclone inner wall. Cyclone efficiency will decrease with increases in gas viscosity, body diameter, gas exit diameter, gas inlet duct area, and gas density.

Cyclones are often used for recovery and recycling of material or as precleaners for more expensive final control devices such as fabric filters or electrostatic precipitators. Cyclones are used for applications such as after spray drying operations in the food and chemical industries; after crushing/grinding/calcining operations in the mineral and chemical industries to collect salable or useful material; for first stage control of PM from sinter plants, roasters, kilns, and furnaces in the metallurgical industries; for catalyst recycling in the fluid-cracking process; and for precleaning fossil-fuel and wood-waste fired industrial and commercial fuel combustion units.

The typical gas flow rates for a single cyclone are 1,060 to 25,400 scfm. Flows that are higher use multiple cyclones in parallel. Inlet gas temperatures are only limited by the material of construction of the cyclone. Cyclones perform more efficiently with higher pollutant loadings, with loadings typically ranging from 1.0 to 100 gr/scf. Cyclones are unable to handle sticky or tacky materials.

Wet Scrubbers

A wet scrubber is an air pollution control device that removes PM from waste gas streams primarily through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. The liquid containing the pollutant is then collected for disposal. There are numerous types of wet scrubbers that remove PM, including venturi, impingement and sieve plate, spray towers, mechanically aided, condensation growth, packed beds, ejector, mobile bed, caternary grid, froth tower, oriented fiber pad, and wetted mist eliminators. Collection efficiencies for wet scrubbers vary with the particle size distribution of the waste gas stream. In general, collection efficiency decreases as the PM size decreases. Collection efficiencies also vary with scrubber type. Collection efficiencies range from greater than 99% for venturi scrubbers to 40-60% (or lower) for simple spray towers. Wet scrubbers are smaller and more compact than baghouses or ESPs. They have lower capital costs and comparable operation and maintenance (O&M) costs. Wet scrubbers are particularly useful in the removal of PM with the following characteristics:

(1) Sticky and/or hygroscopic materials (materials that readily absorb water);
(2) Combustible, corrosive and explosive materials;
(3) Particles which are difficult to remove in their dry form;
(4) PM in the presence of soluble gases; and
(5) PM in waste gas streams with high moisture content.

Some applications of wet scrubbers include the following:

- Condensation scrubbers: for controlling fine PM-containing waste-gas streams.

- Fiber-bed scrubbers (wetted-fiber scrubbers or mist eliminators): for controlling aerosol emissions from chemical, plastics, asphalt, sulfuric acid, and surface coating industries; for controlling lubricant mist emission from rotating machinery and storage tanks; and for eliminating visible plume downstream of other control devices.

- Impingement-plate/tray-tower scrubbers: for the food and agriculture industry and at gray and iron foundries. These types of scrubbers may be used to control other pollutants such as SO_2, VOC, and HAPs in other settings.

- Mechanically-aided scrubbers: for food processing paper, pharmaceuticals, chemicals, plastics, tobacco, fiberglass, ceramics, and fertilizer. Processes controlled include dryers, cookers, crushing and grinding operations, spraying, ventilation, and material handling.

- Orifice scrubbers: for food processing and packaging; pharmaceutical processing and packaging; manufacture of chemicals, rubber and plastics, ceramics, and fertilizer. Processes controlled include dryers, cookers, crushing and grinding operations, spraying, ventilation, and material handling.

- Packed-bed/packed-tower wet scrubbers: for the chemical, aluminum, coke and ferroalloy, food and agriculture, and chromium electroplating industries.

- Spray-chamber/spray-tower wet scrubbers: often used as part of a flue gas desulfurization systems, where they are used to control emissions from coal and oil combustion from electric utilities and industrial sources.

- Venturi scrubbers: for controlling PM emissions from utility, industrial, commercial, and institutional boilers fired with coal, oil, wood, and liquid waste; for sources in the chemical, mineral products, wood, pulp and paper, rock products, and asphalt manufacturing industries; for lead, aluminum, iron and steel, and gray iron production industries; for municipal solid waste incinerators. They are typically used where it is necessary to obtain high collection efficiencies for fine PM.

The primary disadvantage of wet scrubbers is that increased collection efficiency comes at the cost of increased pressure drop across the control system. Another disadvantage is that they generate waste in the form of a sludge which requires treatment and/or disposal. Lastly, downstream plume visibility problems can result unless the added moisture is removed from the gas stream.

Electrostatic Precipitators

An electrostatic precipitator (ESP) is a particle control device that uses electrical forces to move the particles out of the flowing gas stream and onto collector plates. The particles are given an electrical charge by forcing them to pass through a corona, a region in which gaseous ions flow. The electrical field that forces the charged particles to the walls comes from electrodes maintained at high voltage in the center of the flow lane.

Once the particles are collected on the plates, they must be removed from the plates without re-entraining them into the gas stream. This is usually accomplished by knocking them loose from the plates, allowing the collected layer of particles to slide down into a hopper from which they are evacuated. Some precipitators remove the particles by intermittent or continuous washing with water.

Dry-type ESPs are primarily used in the electric utility industry and may also be used by the textile industry, pulp and paper facilities, the metallurgical industry, cement and mineral industry, sulfuric acid manufacturing plants, as well as for coke ovens and hazardous waste incinerators. Dust characteristics are a limiting factor for dry-type ESPs. Sticky, moist, high resistivity, flammable, or explosive dusts and particles are not well-suited for dry-type ESPs. Wet ESPs are used in situations for which dry ESPs are not suited, such as when the material to be collected is wet, sticky, flammable, explosive, or has a high resistivity. Wet ESPs are commonly used by the textile industry, pulp and paper facilities, the metallurgical industry, and sulfuric acid manufacturing plants. The limiting factor for wet ESPs is temperature; typically wet ESPs cannot handle operating temperatures exceeding 170°F.

ESP control efficiencies are very high and can range from 95% to 99.9% due to the strong electrical forces applied to small particles and can handle high temperatures (dry ESPs), pressures, and gas flow rates. The composition of the particulate matter is very important because it influences the conductivity within the dust layers on the collection plate. Wet ESPs are effective at collecting sticky particles and mist, help to cool and condition gas streams, and may provide for control of other aerosolized pollutants in the gas stream. ESPs in general are not suited for use in processes which are highly variable because they are very sensitive to fluctuations in gas stream conditions (flow rates, temperatures, particulate and gas composition, and particulate loadings). They have high capital costs and require large installation space. Dry ESPs are not recommended for removing sticky or moist particles. Wet ESPs can have potential problems with corrosion and they generate a wastewater slurry that must be handled.

Fabric Filtration

A fabric filter unit consists of one or more isolated compartments containing rows of fabric bags in the form of round, flat, or shaped tubes, or pleated cartridges. Particle laden gas passes up (usually) along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, and the cleaned gas stream is vented to the atmosphere. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

Fabric filters collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99 or 99.9%. The layer of dust, or dust cake, collected on the fabric is primarily responsible for such high efficiency. The cake is a barrier with tortuous pores that trap particles as they travel through the cake. Gas temperatures up to about 500°F, with surges to about 550°F, can be accommodated routinely in some configurations. Most of the energy used to operate the system appears as pressure drop across the bags and associated hardware and ducting.

Fabric filters are used where high efficiency particle collection is required and can be used in most any process where dust is generated and can be collected and ducted to a central location. Limitations are imposed by gas characteristics (temperature and corrosivity) and particle characteristics (primarily stickiness) that affect the fabric or its operation and that cannot be economically accommodated. Important process variables include particle characteristics, gas characteristics, and fabric properties. The most important design parameter is the air- or gas-to-cloth ratio (the amount of gas in ft^3/min that penetrates one ft^2 of fabric) and the usual operating parameter of interest is pressure drop across the filter system. Fabric filters are usually made of woven or (more commonly) needle-punched felts sewn to the desired shape, mounted in a plenum with special hardware, and used across a wide range of dust concentrations.

Fabric filters provide high collection efficiency for both coarse and fine particles and are relatively insensitive to fluctuations in gas stream conditions. Operation is simple and fabric filters are useful for collecting particles with resistivities either too low or too high for collection with ESPs. Fabric filters have limited application for high temperatures and corrosive or moist exhaust.

Wet Suppression

Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles. There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve PM control efficiencies of greater than 85%.

Step 2: Eliminate Technically Infeasible Options:

For material handling, all of the control technologies are considered technically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Control Option	Expected Control Efficiency
Fabric filter dust collectors (baghouses)	99+%
Electrostatic precipitators (ESP)	95-99%
Mechanical collectors (such as cyclones or multiclones)	70% - 90%
Wet scrubbers	70% - 90%
Wet suppression	50% - 90%

Step 4: Evaluate the Most Effective Controls and Document the Results

The following tables summarize other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Rail Unloading - Coal

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (Emission unit)	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*railcar dump unloading facility, consisting of: Receiving Pits 1 & 2; Receiving Bins 1 & 2; Drag Flight Feeders 1& 2 (EU-1000)*	*Negative pressure enclosure and baghouse EU-1000 Water spray dust suppression (hoppers and feeder only)*	*PM/PM10/PM2.5: 0.0022 gr/dscf 0.12 lb/hr 5% opacity (6-min avg.)*	5,000 ton/hr
New Steel International	OH-0315 07-00587 (5/6/2008)	Scrap barge unloading to truck and Coal and Iron Ore barge unloading	baghouses 1A and 1B	PM/PM10: 0.0022 gr/dscf, 0.93 lb/hr and 4.07 tpy Fugitive PM: 6.15 tpy and fugitive PM10: 2.84 tpy	
0.0022 gr/dscf is the most stringent grain loading. Therefore, this has been determined to be BACT.					
Southeast Idaho Energy, LLC	ID-0017 P-2008.0066 (2/10/2009)	railcar unloading & storage	baghouses	PM: 0.0009 gr/dscf 0.09 lb/hr 99% CE 5% opacity PM10: 0.0004 gr/dscf 0.04 lb/hr 99% control efficiency	5,000 tons/hr
5% opacity is most stringent limit. Therefore this has been determined to be BACT.					
Permit cited in ID-0017, and later revision P-2009.0127, do not incorporate gr/dscf limits, only lb/hr and opacity. Value of gr/dscf calculated from lb/hr limit and air flow rate provided in the permit conflicts with the gr/dscf value in RBLC. Therefore the gr/dscf value from OH-0315 is considered in determining BACT.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (Emission unit)	Control	BACT	Throughput (ton/yr)
Indiana Gasification - IN	IN-0166 T147-30464-00060 (6/27/2012)	Rail Unloading	Baghouse or dust extraction system	PM/PM10: 0.003 gr/dscf PM2.5: 0.0015 gr/dscf 99.0% CE	-
This includes the most stringent limit (PM2.5), however, this plant was not built and the permit was revoked. Therefore these emission limits cannot be verified and are not considered as BACT.					
East Kentucky Power Cooperative, Inc - J.K. Smith Generating Station	KY-0100 V-05-070 R3 (4/09/2010)	storage piles, railcar unloading, egress to underground conveyor	wet suppression	10% opacity	3000 tph
Ohio River Clean Fuels	OH-0317 02-22896 (11/20/2008)	coal handling and storage	-	PM: 0.09 lb/hr PM10: 0.04 lb/hr	-
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Homeland Energy Solutions	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Coal Unloading/storage	Baghouse and water fogging	PM/PM10: 0.005 gr/dscf	200 tons/hr
Tri-State Generation and Transmission Assoc	CO-0072 12MF322-1 (5/16/2007)	coal handling and storage (train unloading, crushers, transfer, silo and storage piles)	water spray bars	PM: 1.7 tpy PM10: 0.7 tpy	4500000 ton/yr
NRG Coal Handling Plant	TX-0507 8579, PSD-TX-371M4 (4/13/2006)	Rail Unloading	None	PM: 1.15 lb/hr PM10: 0.54 lb/hr	-
Public Service Company Of Colorado Comanche Station	CO-0057 04UNITPB1015 (07/05/2005)	coal handling and storage (includes open storage pile, rail unloading, transfer to pile and transfer to bunkers)	Water Sprays, lower well, dust suppressant, Enclosures and baghouses where feasible	PM/PM10: 0.01 gr/dscf	-
Mesabi Nugget	MN-0061 13700318-001 (6/26/2005)	coal unloading	baghouse	0.005 gr/dscf 10% opacity	
Auburn Nugget	IN-0119 033-19475-00092 (5/31/2005)	coal car unloading	Baghouse	PM: 0.0052 gr/dscf 3% opacity	165 tph

Conveyor transfer - coal

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Unloading Conveyor, Transfer Station (EU-1001)*	*baghouse*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.16 lb/hr (EU-1001) 5% opacity (6-min avg.)*	5,000 tons/hr
		Closed Screw Conveyor	*coal handling system filter (EU-2005)*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.003 lb/hr 5% opacity (6-min avg.)*	500 tons/hr (max) 258 tons/hr (bottleneck ed)

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
US Steel	MN-0084 13700063-004 (12/6/2011)	Reclaim conveyor	Baghouse with leak detection	PM/PM10/PM2.5: 0.002 gr/dscf 0.31 lb/hr, *5% opacity (6-min avg.)*, 95% CE	
0.002 gr/dscf is the most stringent limitation for conveyor transfer, therefore this has been determined to be BACT.					
Great River Energy-Spiritwood	ND-0024 PTC07026 (9/14/2007)	coal handling	baghouse	PM: 0.005 gr/dscf 5% opacity 99.9% CE	85.3 tph
5% opacity is the most stringent opacity. Therefore, this has been determined to be BACT.					
Indiana Gasification - IN	IN-0166 / T147-30464-00060 (6/27/2012)	Conveyor Transfer	Baghouse	PM/PM10: 0.003 gr/dscf *PM2.5: 0.0015 gr/dscf 99.0% CE	750 tph
This plant was not built and the permit was revoked. Therefore these emission limits cannot be verified and are not considered as BACT.					
Holland Board Of Public Works-James Deyoung Plant	MI-0403 25-07 (2/11/2011)	Barge unloading system; all coal fuel conveyors and transfer points; reclaim hopper and vibrating feeders; coal drop points; transfer / crusher house; active storage pile; and inactive storage pile	Fabric filter controls emissions from the transfer/crusher house. conveyors are equipped with three sided enclosures	PM: 0.004 gr/dscf PM10: 0.34 lb/hr 10% opacity	-
Duke Energy-Edwardsport	IN-0139 083-28683-00003 (3/1/2010)	Coal handling and transfer	Baghouse/bin vent collector insertable dust collector	PM: 0.003 gr/dscf 99.0% CE	12000 tph
Sun Coke Energy	OH-0332 P0104768 (2/9/2010)	coal handling, processing and transfer	Enclosure and wet suppression	PM: 4.6 lb/hr (3.47 tpy) PM10: 4.6 lb/hr (1.67 tpy) PM2.5: 4.6 lb/hr (0.52 tpy) VE: 10% Opacity	3750 ton/d
American Municipal Power	OH-0310 P0104461 (10/8/2009)	coal conveying, handling, and crushing	baghouse with option of enclosures, fogging, wet suppression	PM: 77.6 lb/hr (9.8 tpy) PM10: 9.0 tpy	5,553,840 tpy
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	coal and biomass converyors/ transfer towers Totally enclosed towers and transfer points	Baghouse and dust collector	PM10: 0.9 lb/hr (3.9 tpy) 0.005 gr/dscf 99.9% CE 20.0% Opacity NSPS Y	3500 tph
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Martin Marietta	OH-0321 03-17089 (11/13/2008)	coal and coke material handling	building enclosure and high moisture content coal and coke >5%	PM: 3.15 tpy PM10: 0.95 tpy 20% opacity	78,840 tpy
Louisiana Generating, LLC Big Cajun	LA-0223 PSD-LA-660(M-1) (1/8/2008)	conveyors	Wind screens and dry fogging	PM10: 0.06 lb/hr 0.03 tpy	1200 tph
Basin Electric Power Coop.	WY-0064 CT-4631 (10/15/2007)	coal handling	enclosed system with vents feeding fabric filters	PM10: 0.005 gr/dscf	-
Homeland Energy	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	coal receiving and handling	water fogging at coal handling area, baghouse to control storage bin	PM/PM10: 0.005 gr/dscf	200 tph

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Cutler-Magner Co.	WI-0233 05-DCF-412 (8/16/2006)	coal storage and handling	fabric filter baghouse, total enclosure of the process operations	PM: 0.04 lb/hr (0.005 gr/dscf)	-
Public Service Company Of Colorado Comanche Station	CO-0057 04UNITPB1015 07/05/2005)	coal handling and storage (includes open storage pile, rail unloading, transfer to pile and transfer to bunkers)	Water Sprays, lower well, dust suppressant, Enclosures and baghouses where feasible	PM/PM10: 0.01 gr/dscf	-
Montana Dakota Utilities	ND-0021 PTC 05005 (6/3/2005)	coal handling	baghouses	PM: 0.005 gr/dscf	400 tph
Newmont Nevada Energy Investment	NV-0036 AP4911-1349 (5/5/2005)	coal handling	baghouse	PM/PM10: 0.01 gr/dscf	-

Coal Stockpiles

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Conveyor 1, Conveyor 2* *Stacker 1 Boom/Chute, Stacker 2 Boom/Chute* *Coal storage piles (Stockpiles #1A & #1B, #2A & #2B)* *Reclaimer 1, Reclaimer 2* *Conveyor 6, Conveyor 7, Conveyor 9, and Reclaim Transfer Station (EU-1006)*	*negative pressure enclosure and baghouse EU-1006*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.11 lb/hr 5% opacity*	5,000 tons/hr
Southeast Idaho Energy LLC	ID-0017 P-2008.0066 (2/10/2009)	coal/petcoke railcar unloading & storage, SRC01-SRC07	Enclosed railcar unloading at negative pressure. Covered conveyors and enclosed transfer points. Storage in Eurosilo or equivalent. High efficiency baghouses (railcar unloading, conveyors, storage silo vents).	PM: 0.0009 gr/dscf 99% control efficiency 0.09 lb/hr 5% opacity PM10: 0.0004 gr/dscf 99% control efficiency 0.04 lb/hr	5,000 tons/hr
Permit cited in ID-0017, and later revision P-2009.0127, do not incorporate gr/dscf limits, only lb/hr and opacity. Value of gr/dscf calculated from lb/hr limit and air flow rate provided in the permit conflicts with the gr/dscf value in RBLC. Therefore the concentration equivalent to the entry below, also equivalent to the value from the conveyor transfer table above, is determined to be BACT.					
US Steel Corp - Keetac: Keewatin, MN	MN-0084 13700063-004 (12/6/2011)	coal bin	Baghouse (bin vent)	PM/PM10/PM2.5: 0.14 lb/hr (0.002 gr/dscf) 95.0% CE	-

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Ag Processing Inc.	NE-0059 CP14-007 (3/25/2015)	grain receiving and handling (6 units routed to 1 stack. Grain Truck Dump Pit #1, Grain Elevator #1, Grain Truck Dump Pit #2, Grain Elevator #2, Conveyor #1, and Scalper)	baghouse	PM/PM10: 0.003 gr/dscf 0.82 lb.hr	20,000 bu/hr
Grain handling and storage processes may not be representative of BACT for coal.					
University of Northern Iowa	IA-0086 02-111 (5/3/2007)	Coal system - bunker #3 silo	baghouse	PM/PM10: 0.005 gr/dscf VE: 5% opacity	27.4 lb/hr
Value presented as throughput may not be accurate.					

Coal Milling/Drying

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Conveyor 8* *Coal milling/drying*	*Loop purge baghouse (EU-1008)*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.26 lb/hr No VE except 1 min in any 60 min*	500 tons/hr (max) 258 tons/hr (bottlenecked)
Essar Steel Minnesota	MN-0085 06100067-004 (5/10/2012)	Taconite - secondary screening crusher/cobber line	Fabric filter with leak detection	PM/PM10/PM2.5: 0.002 gr/dscf 0.39 lb/hr VE: 5% for 6-min avg.	
0.002 gr/dscf is the most stringent limit. Therefore, this has been determined to be BACT.					
American Municipal Power	OH-0310 P0104461 (10/8/2009)	coal conveying/handling/crushing	baghouse with option of enclosures, fogging, wet suppression	PM: 77.6 lb/hr and 9.8 tpy PM10: 9.0 tpy No VE except 1 min in any 60 min	
VE: 0% opacity except for 1 min in any 60 min is the most stringent VE. Therefore, this has been determined to be BACT					
Wolverine Power Supply	MI-0400 317-07 (6/29/2011)	coal crushers	baghouse	2.0e-5 gr/dscf PM10/PM2.5: 27.6e-4 lb/hr VE: 10% opacity drop and transfer points, 5% opacity dust collector 99% CE	
State tracking system does not show a Part 70 permit for a source in the county identified in the RBLC entry. The source may not have been constructed. Therefore this is not considered representative of BACT for the proposed source.					
East Kentucky Power Cooperative, Inc - J.K. Smith Generating Station	KY-0100 V-05-070 R3 (4/09/2010)	coal crushing and silo storage	baghouse	0.005 gr/dscf	
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	coal and biomass crusher houses	Baghouse and totally enclosed crusher houses	0.005 gr/dscf 99.9% CE PM10: 1.2 lb/hr & 5.3 tpy 20% opacity	-
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Louisiana Generating, LLC Big Cajun	LA-0223 PSD-LA-660(M-1) (1/8/2008)	fuel crusher house	baghouse	0.04 lb/hr and 0.06 tpy	
NRG Coal Handling Plant	TX-0507 8579, PSD-TX-371M4 (4/13/2006)	crusher house	none	PM: 0.76 lb/hr & 3.33 tpy PM10: 0.36 lb/hr & 1.58 tpy	
Cleveland Cliffs, Northshore Mining	MN-0064 07500003-003 (3/22/2006)	Taconite - tertiary crushing	baghouse	PM/PM10: 0.0025 gr/dscf	

Material Storage in Silos and Bins

The additives used at this source consist of different types of dry powdery type materials. A search in the RBLC only includes one entry for "pneumatic" and a few entries for "additive" (included in the table below).

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*EU-1501 Coarse additive unloading*	*Baghouse EU-1501*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.016 lb/hr*	-
		EU-1502 Fine additive unloading	*Baghouse EU-1502*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.018 lb/hr*	
		EU-1503 Sodium sulfide unloading	*Baghouse EU-1503*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.013 lb/hr*	
		EU-2006 Coarse additive conveyor	*Filter EU-2006*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.004 lb/hr*	
		EU-2007 Fine additive handling system	*Filter EU-2007*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.004 lb/hr*	
		EU-2008 Sodium sulfide handling system	*Filter EU-2008*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.001 lb/hr*	
		Residue conveyor	*total enclosure, silo/hopper bin vent filters*	*see EU-5009, EU-5010, and EU-5011*	
		EU-5009 Residue container loading station	*Filter EU-5009*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.001 lb/hr*	
		EU-5010 Residue rail storage silo, loading hoppers EU-5005 & EU-5006	*Filter EU-5010*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.003 lb/hr*	
		EU-5011 Residue swing storage silo, loading hoppers EU-5007 & EU-5008	*Filter EU-5011*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.003 lb/hr*	
		EU-6501 Lime unloading	*Baghouse EU-6501*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.01 lb/hr*	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Mag Pellet, LLC (formerly Magnetation)	IN-0167 T181-32081-00054 (4/16/2013)	Pneumatic transfer for each of the following:	see below:		-
		Coke Breeze grinding (EU004b),	Baghouse	PM/PM10/PM2.5: 0.002 gr/dscf and 0.1388 lb/hr	
		WBE Lime Storage Area (EU020) Bentonite	Bin Vent	PM/PM10/PM2.5: 0.002 gr/dscf and 0.02 lb/hr	
		Unloading and Storage Area (EU005)	Bin Vent Filter	PM/PM10/PM2.5: 0.002 gr/dscf and 0.0496 lb/hr	
		Ground Limestone and Dolomite Area Additive System (EU010)	Baghouse	PM/PM10/PM2.5: 0.002 gr/dscf and 0.32 lb/hr	
US Steel Corp - Keetac: Keewatin, MN	MN-0084 13700063-004 (12/6/2011)	This process isn't pneumatic. Therefore, it wasn't considered a similar process for this BACT review.			
		Bentonite Bin	PM: Baghouse/Bin Vent	0.002 gr/dscf and 0.021 lb/hr	
		Alternative Fuels Intermediate Dry Fuel Silo	PM: Baghouse/Bin Vent	0.002 gr/dscf and 0.11 lb/hr)	
		Alternative Fuels Prepared Dry Fuel Silo	PM: Baghouse/Bin Vent,	0.002 gr/dscf and 0.07 lb/hr	
		Final Transfer Conveyors and Loadout Conveyor	PM: Baghouse with Leak Detection,	0.002 gr/dscf and 0.21 lb/hr	
		Reclaim Conveyor	PM: Baghouse with Leak Detection	0.002 gr/dscf and 0.31 lb/hr	
		Emergency Pellet Conveyor Transfer	PM: Baghouse with Leak Detection	0.002 gr/dscf and 0.21 lb/hr	
		Coal Bin 2	PM: Baghouse/Bin Vent	0.002 gr/dscf and 0.14 lb/hr	
		Limestone Bin	PM: Baghouse/Bin Vent	0.002 gr/dscf and 0.21 lb/hr	
		Mill Feeder 1	PM: Baghouse with Leak Detection	0.002 gr/dscf and 0.51 lb/hr	
		Lime Bin	PM: Baghouse/Bin Vent	0.002 gr/dscf and 0.02 lb/hr	
0.002 gr/dscf is the most stringent grain loading. Therefore, this has been determined to be BACT.					
New Steel International: Haverhill, OH	OH-0315 07-00587 (5/6/2008)	Alloy, Flux, Carbon, Limestone, & Coke Handling	PM: Enclosures/Baghouse	1.4 lb/hr, 6.13 tons/yr, 0.0022 gr/dscf	
New Steel International: Haverhill, OH	OH-0315 07-00587 (5/6/2008)	Conveyors, Hoppers, Screens to Rotary Hearth Furnace (227 tons/yr)	PM: Baghouse	1.4 lb/hr, 6.13 tons/yr, 0.0022 gr/dscf	
Minnesota Steel Industries	MN-0070 06100067-001 (9/7/2007)	Additive Handling	Baghouse	0.0025 gr/dscf	

Additive Preparation

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Fine additive production system (EU-1504)*	*cartridge filter*	*PM/PM10/PM2.5: 0.002 gr/dscf 0.004 lb/hr*	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Essar Steel Minnesota LLC	MN-0085 06100067-004 (5/10/2012)	Primary Grinding Mill Line 3	Baghouse w/ leak detection	PM/PM10/PM2.5: 0.002 gr/dscf 0.23 lb/hr	
United States Steel Corp	MN-0084 13700063-004 (12/6/2011)	Alternative fuels hammermill #1	Baghouse w/ leak detection	PM/PM10/PM2.5: 0.002 gr/dscf 0.41 lb/hr Opacity 5% (6 min avg)	
Alliant Energy	WI-0262 17-DCF-070 (6/30/2017)	Coal crusher house, P06	building enclosure, dust collection system, baghouse w/ leak detection	PM/PM10/PM2.5: 0.002 gr/dscf (filt PM10) 0.003 gr/dscf (ttl PM) 1.12 lb/hr 5% M9 opacity	
Donlin Gold LLC	AK-0084 AQ0934CPT 01 (6/30/2017)	Ore crushing and transfers (dust collector)	dust collector	PM/PM10/PM2.5: 0.010 gr/dscf	5100 tph
Wolverine Power Supply Cooperative Inc	MI-0400 317-07 (6/29/2011)	coal crushers	fabric filter	FPM: 2.0E-05 gr/dscf TPM10/TPM2.5: 2.76E-03 lb/hr 5% opacity (dust collector)	
State tracking system does not show a Part 70 permit for a source in the county identified in the RBLC entry. The source may not have been constructed. Therefore this is not considered representative of BACT for the proposed source.					
East Kentucky Power Cooperative Inc	KY-0100 V-05-070R3 (4/9/2010)	Coal crushing & silo storage	fabric filter	PM10: 0.005 gr/dscf	
Ohio River Clean Fuels LLC	OH-0317 02-22896 (11/20/2008)	Coal & biomass crusher houses (2)	baghouse with dust collector, totally enclosed crusher houses	1.20 lb/hr (ea baghouse) 5.30 tpy 0.005 gr/dscf	
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Martin Mariette Magnesia Specialties LLC	OH-0321 03-17089 (11/13/2008)	stone crushing and screening	maintain inherent moisture and include many vibratory feeders and material handling processes within tunnel enclosures	PM: 26.90 tpy PM10: 9.79 tpy 15% opacity (crushers, 6-min avg)	
Louisiana Generating LLC	LA-0223 PSD-LA-660 (M-1) (1/8/2008)	Fuel crusher house	fabric filter	0.04 lb/hr 0.06 tpy	
		Limestone silo and crusher		0.02 lb/hr 0.02 tpy	

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), BACT shall be the following:

(a)

(1)

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	gr/dscf	lb/hr
Railcar unloading, including: Receiving Pits 1 & 2 Receiving Bins 1 & 2 Drag Flight Feeders 1& 2 (EU-1000)	Negative pressure enclosure and Baghouse EU-1000 (stack EU-1000) Water spray dust suppression (bins & feeders only)	PM	0.0022	0.12
		PM_{10}[1]	0.0022	0.12
		$PM_{2.5}$[1]	0.0022	0.12
Transfer station, including: Unloading Conveyor (EU-1001)	Baghouse EU-1001 (stack EU-1001)	PM	0.002	0.16
		PM_{10}[1]	0.002	0.16
		$PM_{2.5}$[1]	0.002	0.16
Coal storage enclosure 1, including Conveyor 1 Stacker 1 Boom/Chute Stockpiles #1A & #1B Reclaimer 1 Coal storage enclosure 2, including: Conveyor 2 Stacker 2 Boom/Chute Stockpiles #2A & #2B Reclaimer 2 Reclaim transfer station, including: Conveyor 6 Conveyor 7 Conveyor 9	Negative pressure enclosure and Baghouse EU-1006 (stack EU-1006)	PM	0.002	0.11
		PM_{10}[1]	0.002	0.11
		$PM_{2.5}$[1]	0.002	0.11
Coal drying loop purge, including: Conveyor 8 Coal mill & pulverizer Coal Dryer	Loop Purge Baghouse (stack EU-1008)	PM	0.002	0.26
		PM_{10}[1]	0.002	0.26
		$PM_{2.5}$[1]	0.002	0.26

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	gr/dscf	lb/hr
Enclosed screw conveyor to Block 2000 feed premix drum	Coal Handling System Filter (stack EU-2005)	PM	0.002	0.003
		PM_{10}[1]	0.002	0.003
		$PM_{2.5}$[1]	0.002	0.003

Notes:
1. PM_{10} and $PM_{2.5}$ include both filterable and condensable.

(2) There shall be no (0%) visible emissions from the entrance and exit doors of the unloading enclosure at any time.

(b) Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the material handling operations shall be as follows:

(1)

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	gr/dscf	lb/hr
Coarse additive silo, T34 (EU-1501)	Baghouse EU-1501 (stack EU-1501)	PM	0.002	0.016
		PM_{10}[1]	0.002	0.016
		$PM_{2.5}$[1]	0.002	0.016
Fine additive silo, T33 (EU-1502)	Baghouse EU-1502 (stack EU-1502)	PM	0.002	0.018
		PM_{10}[1]	0.002	0.018
		$PM_{2.5}$[1]	0.002	0.018
Na_2S silo, T35 (EU-1503)	Baghouse EU-1503 (stack EU-1503)	PM	0.002	0.013
		PM_{10}[1]	0.002	0.013
		$PM_{2.5}$[1]	0.002	0.013
Fine additive production system	Baghouse EU-1504 (stack EU-1504)	PM	0.002	0.004
		PM_{10}[1]	0.002	0.004
		$PM_{2.5}$[1]	0.002	0.004
Coarse additive screw conveyor	Coarse additive system filter (stack EU-2006)	PM	0.002	0.004
		PM_{10}[1]	0.002	0.004
		$PM_{2.5}$[1]	0.002	0.004
Fine additive transfer system	Fine additive system filter (stack EU-2007)	PM	0.002	0.004
		PM_{10}[1]	0.002	0.004
		$PM_{2.5}$[1]	0.002	0.004
Na_2S slurry preparation system	Na_2S handling system filter (stack EU-2008)	PM	0.002	0.001
		PM_{10}[1]	0.002	0.001
		$PM_{2.5}$[1]	0.002	0.001
Residue bulk container loading and residue transfer conveyors (EU-5009)	Filter EU-5009 (stack EU-5009)	PM	0.002	0.001
		PM_{10}[1]	0.002	0.001
		$PM_{2.5}$[1]	0.002	0.001
Residue rail storage silo	Filter EU-5010	PM	0.002	0.003

Emission Unit Description (ID)	Control Device (Stack ID)	Emission Limitations		
		Pollutant	gr/dscf	lb/hr
(EU-5010), loading hoppers (EU-5005, EU-5006), and residue transfer conveyors	(stack EU-5010)	PM_{10}[1]	0.002	0.003
		$PM_{2.5}$[1]	0.002	0.003
Residue swing storage silo (EU-5011), loading hoppers (EU-5007, EU-5008), and residue transfer conveyors	Filter EU-5011 (stack EU-5011)	PM	0.002	0.003
		PM_{10}[1]	0.002	0.003
		$PM_{2.5}$[1]	0.002	0.003
Lime silo (EU-6501)	Filter EU-6501 (stack EU-6501)	PM	0.002	0.01
		PM_{10}[1]	0.002	0.01
		$PM_{2.5}$[1]	0.002	0.01

Notes:
1. PM_{10} and $PM_{2.5}$ include both filterable and condensable.

(2) Transfers from the loading hoppers to transports shall employ choke flow-practices

(3) There shall be no visible emissions from transfers from the loading hoppers and from hoppers to transports.

BACT AnalysisProcess fuel gas-fired heaters and boiler

PM/PM10/PM2.5

Step 1: Identify Potential Control Technologies

PM/PM10/PM2.5 emissions can be controlled with the following control technologies:

(1) Good Combustion Practices

Good Combustion Practices
Good combustion practices are a form of preventive controls that may have only a small effect on pollutant formation except in combination with other controls. Some principles of good combustion practice are taken as incorporated at the equipment design stage, such as proper design of burners and firebox components and ensuring adequate residence time. Other principles, such as minimizing air infiltration and maintaining equipment in accordance with a manufacturer's specification, may be taken as incorporated into the preventive maintenance plan for a unit. The element of good combustion practices that may have the most direct effect, and that may be considered as a control technology, is the control of the fuel-to-air combustion ratio, which can be achieved manually through tuneups as required by the NESHAP, 40 CFR 63, Subpart DDDDD or through control equipment such as an oxygen trim system.

Step 2: Eliminate Technically Infeasible Options

A search of the USEPA's RACT/BACT/LAER Clearinghouse indicates the use of good combustion practice for gas-fired combustion units is the best control for PM/PM10/PM2.5 emissions. Natural gas combustion is already efficient. It is possible to achieve PM/PM10/PM2.5 reductions from an add-on control device; however, any add-on control technology would not be cost effective since the PM/PM10/PM2.5 concentration in these units is relatively low. Good Combustion Practices are a technically feasible option.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Combustion Units (<100 MMBtu/hr) - PM/PM10/PM2.5

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-1007 Coal milling and drying heater*	gas fuel, GCP[2]	PM (filterable): 0.11 lb/hr 0.0019 lb/MMBtu PM10: 0.42 lb/hr 0.0075 lb/MMBtu PM2.5: 0.42 lb/hr 0.0075 lb/MMBtu	*55.80*
		EU-2002 Treat gas heater		PM (filterable): 0.10 lb/hr 0.0019 lb/MMBtu PM10: 0.40 lb/hr 0.0075 lb/MMBtu PM2.5: 0.40 lb/hr 0.0075 lb/MMBtu	*52.80*
		EU-2003 Vacuum column feed heater		PM: 1.71E-02 lb/hr 0.0019 lb/MMBtu PM10: 6.75E-02 lb/hr 0.0075 lb/MMBtu PM2.5: 6.75E-02 lb/hr 0.0075 lb/MMBtu	*9.00*
		EU-6000 Boiler		PM (filterable): 0.13 lb/hr 0.0019 lb/MMBtu PM10: 0.53 lb/hr 0.0075 lb/MMBtu PM2.5: 0.53 lb/hr 0.0075 lb/MMBtu	*68.50*

<table>
<tr><th>Facility - County, State</th><th>RBLC ID / Permit # (Issuance Date)</th><th>Process (All natural gas-fired unless otherwise noted)</th><th>Control</th><th>BACT</th><th>Rating (MMBtu/hr)</th></tr>
<tr><td>Holly Refinery & Marketing-Tulsa LLC</td><td>OK-0167
2012-1062-C(M-1)PSD
(4/20/2015)</td><td>Process heaters</td><td>gas fuel</td><td>PM10:
0.0075 lb/MMBtu
PM2.5:
0.0075 lb/MMBtu</td><td>10.00
25.00
42.00
50.00</td></tr>
<tr><td>Holly Refinery & Marketing-Tulsa LLC</td><td>OK-0166
2010-599-C(M-3)
(4/20/2015)</td><td>Process heater (refinery fuel gas)</td><td>gas fuel</td><td>PM10:
0.0075 lb/MMBtu
PM2.5:
0.0075 lb/MMBtu</td><td>76.00</td></tr>
<tr><td colspan="6">The entries above are the most restrictive limits found on a lb/MMBtu basis and are selected as BACT.</td></tr>
<tr><td rowspan="2">ExxonMobil Oil Corp.</td><td rowspan="2">TX-0832
PSDTX768M1,
PSDTX799,
PSDTX802
(1/9/2018)</td><td>F-2001 Kero HDT Charge Heater and F-2002 Kero HDT Stripper Reboiler (natural gas/refinery gas)</td><td rowspan="2">good combustion and use of gaseous fuel</td><td>PM:
0.67 lb/hr
PM10:
0.67 lb/hr
PM2.5:
0.67 lb/hr
(all filterable)
(equivalent to 0.0078 lb/MMBtu)</td><td>85.50</td></tr>
<tr><td>F-3001 Diesel DHDT charge heater & F-3002 diesel DHDT stripper reboiler (natural gas /refinery gas)</td><td>PM:
0.49 lb/hr
PM10:
0.49 lb/hr
PM2.5:
0.49 lb/hr
(all filterable)
(equivalent to 0.0074 lb/MMBtu)</td><td>66.50</td></tr>
<tr><td colspan="6">The entries above are the most restrictive found for work practices and are selected as BACT. Oklahoma citations are taken as combined filterable and condensible fractions and therefore more restrictive than the lower Texas value for filterable particulate matter only.</td></tr>
<tr><td rowspan="3">CHS McPherson Refinery Inc</td><td rowspan="3">KS-0032
C-13055
(12/12/2015)</td><td>Process heaters (refinery fuel gas)</td><td>-</td><td>PM/PM10:
0.08 lb/MMBtu</td><td>-</td></tr>
<tr><td>#2 Hydrogen Unit heater</td><td>-</td><td>PM/PM10:
0.011 lb/MMBtu</td><td>-</td></tr>
<tr><td>Hydrogen Plant heater</td><td>-</td><td>PM/PM10:
0.0116 lb/MMBtu</td><td>-</td></tr>
</table>

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Sasol Chemicals (USA) LLC	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	DW reactor feed heaters (EQT 738 & 775) (process gas)	gas fuel, GCP	PM10: 0.46 lb/hr 1.54 tpy 0.0075 lb/MMBtu PM2.5: 0.46 lb/hr 1.54 tpy 0.0075 lb/MMBtu	56.80
		Base oils DW reactor feed heater (EQT 776) (process gas)		PM10: 0.26 lb/hr 0.84 tpy 0.0075 lb/MMBtu PM2.5: 0.26 lb/hr 0.84 tpy 0.0075 lb/MMBtu	31.00
		HC reactor feed heaters (EQT 736 & 754) (process gas)		PM10: 0.56 lb/hr 1.92 tpy 0.0075 lb/MMBtu PM2.5: 0.56 lb/hr 1.92 tpy 0.0075 lb/MMBtu	70.80
		Process heater (EQT 702) (process gas)		PM10: 0.58 lb/hr 2.01 tpy 0.0075 lb/MMBtu PM2.5: 0.58 lb/hr 2.01 tpy 0.0075 lb/MMBtu	73.80
		Base oils light vacuum feed heater (EQT 777) (process gas)		PM10: 0.56 lb/hr 1.94 tpy 0.0075 lb/MMBtu PM2.5: 0.56 lb/hr 1.94 tpy 0.0075 lb/MMBtu	71.20
		Base oils heavy vacuum feed heater (EQT 778)		PM10: 0.11 lb/hr 0.27 tpy 0.0075 lb/MMBtu PM2.5: 0.11 lb/hr 0.27 tpy 0.0075 lb/MMBtu	10.00
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Reactor feed heater (EQT 1160)	gas fuel, GCP	PM10: 0.13 lb/hr 0.49 tpy 0.0075 lb/MMBtu PM2.5: 0.13 lb/hr 0.49 tpy 0.0075 lb/MMBtu	18.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
	LA-0298 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 772) (process gas)		PM10: 0.30 lb/hr 1.08 tpy 0.0075 lb/MMBtu PM2.5: 0.30 lb/hr 1.08 tpy 0.0075 lb/MMBtu	40.00
	LA-0302 PSD-LA-779 (5/23/2014)	Process heat boilers (EQT 1008 & 1009)		PM10: 0.58 lb/hr 1.87 tpy 0.0075 lb/MMBtu PM2.5: 0.58 lb/hr 1.87 tpy 0.0075 lb/MMBtu	78.00 ea
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-1 (natural gas and process fuel gas)	GCP	-	36.00
		heater 94-21			48.00
		heater 94-29			75.00
		heater/reboiler 2004-1			86.00
		heater/reboiler 2004-2			24.00
		heater/reboiler 2004-3			52.00
		heater/reboiler 2004-4			86.00
		heater/reboiler 2005-8			100.00
		heater/reboiler 2005-9			83.00
		heater/reboiler 2005-23			100.00
		heater/reboiler 2005-24			83.00
		CPF heater H-39-03	GCP	PM10: 0.0074 lb/MMBtu	68.00
		CPF heater H-39-02			90.00
		DHT heater 4-81	gas fuel	-	70.00
		DHT heater 5-81			70.00
The Louisiana determination of good combustion practices as BACT is not considered applicable because IDEM finds that the operating permit does not incorporate monitoring and record keeping conditions that demonstrate compliance with the BACT requirement.					

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, and periodic tuneups that are required for units subject to 40 CFR 63, Subpart DDDDD.*

Combustion Units (>100 MMBtu/hr) - $PM/PM_{10}/PM_{2.5}$

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-2001* *Feed heater*	gas fuel, GCP[2]	PM (filterable): 0.24 lb/hr 0.0019 lb/MMBtu PM10: 0.96 lb/hr 0.0075 lb/MMBtu PM2.5: 0.96 lb/hr 0.0075 lb/MMBtu	*128.40*
		EU-2004 *Fractionator heater*		PM (filterable): 0.30 lb/hr 0.0019 lb/MMBtu PM10: 1.17 lb/hr 0.0075 lb/MMBtu PM2.5: 1.17 lb/hr 0.0075 lb/MMBtu	*156.00*
Holly Refinery & Marketing-Tulsa LLC	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	CDU atmospheric tower heater (refinery fuel gas)	gas fuel	PM10: 0.0075 lb/MMBtu PM2.5: 0.0075 lb/MMBtu	248.00
	OK-0170 2012-1062-C(M-6) (11/12/2015)	Process heater (H-205) (refinery fuel gas)	gas fuel, GCP	PM2.5: 0.0075 lb/MMBtu	100.00
The entries above are the most restrictive limits found and are selected as BACT.					
Sasol Chemicals (USA) LLC	LA-0290 PSD-LA-778 (5/23/2014) (GTL unit)	Hot oil heater (process gas)	gas fuel, GCP	PM10: 1.56 lb/hr 5.70 tpy 0.0075 lb/MMBtu PM2.5: 1.56 lb/hr 5.70 tpy 0.0075 lb/MMBtu	171.00
	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	Fractionator feed heaters (EQT 737 & 774) (process gas)		PM10: 1.89 lb/hr 6.76 tpy 0.0075 lb/MMBtu PM2.5: 1.89 lb/hr 6.76 tpy 0.0075 lb/MMBtu	248.70
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 1161) (process gas)	gas fuel, GCP	PM10: 1.79 lb/hr 6.53 tpy 0.0075 lb/MMBtu PM2.5: 1.79 lb/hr 6.53 tpy 0.0075 lb/MMBtu	240.00
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-4 (refinery fuel gas)	comply with 40 CFR 60, subparts NNN and RRR	-	108.00
		heater 2008-5			123.00
		heater 2008-7			122.00
		heater 2008-9			122.00
		heater/reboiler 6-81	gas fuel, GCP	-	135.00
The Louisiana determination of good combustion practices as BACT is not considered applicable because IDEM finds that the operating permit does not incorporate monitoring and record keeping conditions that demonstrate compliance with the BACT requirement.					
Shintech Louisiana LLC	LA-0204 PSD-LA-709(M-1) (2/27/2009)	Boilers A & B	natural gas, GCP	0.005 lb/MMBtu	250 ea
		Boilers C & D			
This source is in SIC code 2821, not 2911 like the proposed source. RBLC process code is 12.390, for "other gaseous fuels and gaseous fuel mixtures" but entries specify that the units burn natural gas. Therefore these entries may not represent BACT for the proposed source and have not been considered.					

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, and periodic tuneups that are required for units subject to 40 CFR 63, Subpart DDDDD.*

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the fuel combustion units listed in the table below shall be as follows:

Description	Unit ID
Coal dryer heater	EU-1007
Feed heater	EU-2001
Treat gas heater	EU-2002
Vacuum column feed heater	EU-2003
Fractionator heater	EU-2004
Package boiler	EU-6000

(a) The units shall burn only natural gas and process off-gas.

(b) The units shall use good combustion practices. Good combustion practices shall include installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, on each fuel gas combustion unit.

(c) Particulate matter emissions shall not exceed:

Emission Limitations			
Unit ID	Pollutant	lb/MMBtu	lb/hr
EU-1007	$PM_{FILTERABLE}$	0.0019	0.11
	PM_{10}	0.0075	0.42
	$PM_{2.5}$	0.0075	0.42
EU-2001	$PM_{FILTERABLE}$	0.0019	0.24
	PM_{10}	0.0075	0.96
	$PM_{2.5}$	0.0075	0.96
EU-2002	$PM_{FILTERABLE}$	0.0019	0.10

Emission Limitations			
Unit ID	Pollutant	lb/MMBtu	lb/hr
	PM_{10}	0.0075	0.40
	$PM_{2.5}$	0.0075	0.40
EU-2003	$PM_{FILTERABLE}$	0.0019	1.71E-02
	PM_{10}	0.0075	6.75E-02
	$PM_{2.5}$	0.0075	6.75E-02
EU-2004	$PM_{FILTERABLE}$	0.0019	0.30
	PM_{10}	0.0075	1.17
	$PM_{2.5}$	0.0075	1.17
EU-6000	$PM_{FILTERABLE}$	0.0019	0.13
	PM_{10}	0.0075	0.51
	$PM_{2.5}$	0.0075	0.51

Notes:
1. tons/yr = tons per twelve (12) consecutive month period

<u>SO_2</u>

<u>Step 1: Identify Potential Control Technologies</u>

Sulfur Dioxide (SO_2) emissions result from the oxidation of fuel-bound sulfur, with emissions dependent upon the sulfur content of the fuel. Sulfur Dioxide (SO_2) emissions are generally controlled with add-on control equipment designed to capture the emissions prior to the time they are exhausted to the atmosphere.

(a) Flue Gas Desulfurization (FGD) System);
  (1) Wet Scrubbing
  (2) Spray Dryer Absorption (SDA)
  (3) Dry Sorbent Injection (DSI)
(b) Fuel Specification.
(c) Good Combustion Practices

The choice of which technology is most appropriate for a specific application depends upon several factors, including particle size to be collected, particle loading, stack gas flow rate, stack gas physical characteristics (e.g., temperature, moisture content, presence of reactive materials), and desired collection efficiency.

Flue Gas Desulfurization (FGD) System (Dry and Wet Scrubbers)
A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. FGD is an established technology. FGD typically operates at a temperature of approximately 300°F to 700°F (wet) and 300°F to 1830°F (dry). The FGD has a waste stream inlet pollutant concentration of 2,000 ppmv. Absorption of SO_2 is accomplished by the contact between the exhaust and an alkaline reagent, which results in the formation of neutral salts. Wet systems employ reagents using packed or spray towers and generate wastewater streams, while dry systems inject slurry reagent into the exhaust stream to react, dry and be removed downstream by particulate control equipment. Chlorine emissions can result in salt deposition within the absorber and in downstream equipment. Wet systems may require flue gas re-heating downstream of the absorber to prevent corrosive condensation. Inlet streams for dry systems must be cooled as appropriate, and dry systems require use of particulate controls to collect the solid netural salts.

(1) Wet Scrubbing Wet scrubbers are regenerative processes which are designed to maximize contact between the exhaust gas and an absorbing liquid. The exhaust gas is scrubbed with a 5 -

15 percent slurry, comprised of lime (CaO) or limestone ($CaCO_3$) in suspension. The SO_2 in the exhaust gas reacts with the CaO or $CaCO_3$ to form calcium sulfite ($CaSO_3.2H_2O$) and calcium sulfate ($CaSO_4$). The scrubbing liquor is continuously recycled to the scrubbing tower after fresh lime or limestone has been added.

The types of scrubbers which can adequately disperse the scrubbing liquid include packed towers, plate or tray towers, spray chambers, and venturi scrubbers. In addition to calcium sulfite/sulfate, numerous other absorbents are available including sodium solutions and ammonia-based solutions.

(2) Spray Dryer Absorption (SDA) - An alternative to wet scrubbing is a process known as dry scrubbing, or spray-dryer absorption (SDA). As in wet scrubbing, the gas-phase SO_2 is removed by intimate contact with a suitable absorbing solution. Typically, this may be a solution of sodium carbonate (Na_2CO_3) or slaked lime [$Ca(OH)_2$]. In SDA systems the solution is pumped to rotary atomizers, which create a spray of very fine droplets. The droplets mix with the incoming SO_2-laden exhaust gas in a very large chamber and subsequent absorption leads to the formation of sulfites and sulfates within the droplets. Almost simultaneously, the sensible heat of the exhaust gas which enters the chamber evaporates the water in the droplets, forming a dry powder before the gas leaves the spray dryer. The temperature of the desulfurized gas stream leaving the spray dryer is now approximately 30 - 50^{o}F above its dew point.

The exhaust gas from the SDA system contains a particulate mixture which includes reacted products. Typically, baghouses employing teflon-coated fiberglass bags (to minimize bag corrosion) are utilized to collect the precipitated particulates.

(3) Dry Sorbent Injection (DSI) - This control option typically involves the injection of dry powders into either the furnace or post-furnace region of utility-sized boilers. This process was developed as a lower cost option to conventional FGD technology. Since the sorbent is injected directly into the exhaust gas stream, the mixing offered by the dry scrubber tower is not realized. The maximum efficiency realized for this SO_2 control technology is estimated to be fairly nominal. It is felt that if sufficient amounts of reactants are introduced into the flue gas, there is a possibility of some degree of mixing and reaction. The science is inexact and the coupling of reactant dosage and in-flue mixing which impacts the SO_2 control efficiency is susceptible to variability in SO_2 concentrations.

Dry Sorbent Injection
A post-combustion technology in which a calcium or sodium-based sorbent reacts with SO_2 and SO_3 and is removed downstream by particulate control equipment. The system requires use of particulate controls to collect the reaction solids. Dry sorbent injection is not listed in the RBLC as BACT for the control of SO_2 emissions for auxiliary boilers. Technology has not been applied to natural gas combustion turbines due to very low SO_2 emissions. Controls would not provide any measurable emission reduction.

Fuel Specifications
Combusting only clean natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas has a very low potential for generating SO_2 emissions.

Good Combustion Practices
Good combustion practices are a form of preventive controls that may have only a small effect on pollutant formation except in combination with other controls. Some principles of good combustion practice are taken as incorporated at the equipment design stage, such as proper design of burners and firebox components and ensuring adequate residence time. Other principles, such as minimizing air infiltration and maintaining equipment in accordance with a manufacturer's specification, may be taken as incorporated into the preventive maintenance plan for a unit. The element of good combustion practices that may have the most direct effect, and that may be considered as a control technology, is the control of

the fuel-to-air combustion ratio, which can be achieved manually through tuneups as required by the NESHAP, 40 CFR 63, Subpart DDDDD or through control equipment such as an oxygen trim system.

Step 2: Eliminate Technically Infeasible Options:

FGD systems are not listed in the RBLC as BACT for the control of SO_2 emissions for process heaters and/or boilers. Technology has not been applied to natural gas units due to very low SO_2 emissions. Controls would not provide any measurable emission reduction and would not be economically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Good Combustion Practices and use of low-sulfur fuel gas are the only feasible option.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Combustion Units - SO_2

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-1007 Coal milling and drying heater*	*The average sulfur content of the fuel gas combusted shall not exceed 0.005 gr/scf per twelve (12) consecutive month period with compliance determined at the end of each month, good combustion practices[1].*	*0.35 tpy*	*55.80*
		EU-2001 Feed heater		*0.80 tpy*	*128.40*
		EU-2002 Treat gas heater		*0.33 tpy*	*52.80*
		EU-2003 Vacuum column feed heater		*0.06 tpy*	*9.00*
		EU-2004 Fractionator heater		*0.97 tpy*	*156.00*
		EU-6000 Boiler		*0.42 tpy*	*68.50*
The source has proposed a more restrictive limit for fuel gas sulfur content than entries in the RBLC database. Therefore, this is determined to be BACT.					
ExxonMobil Oil Corp.	TX-0832 PSDTX768M1, PSDTX799, PSDTX802 (1/9/2018)	F-1001 Crude Charge Furnace (natural gas/refinery gas)	use low sulfur gas fuel	162 ppmvd hourly 60 ppmvd annual	630.80
		F-2001 Kero HDT Charge Heater and F-2002 Kero HDT Stripper Reboiler (natural gas/refinery gas)	good combustion and use of gaseous fuel		85.50
		F-3001 Diesel DHDT charge heater & F-3002 diesel DHDT stripper reboiler (natural gas /refinery gas)			66.50
The entries above are the most restrictive found for work practices and are selected as BACT.					
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Process heaters	-	H_2S limited: 160 ppmv @ 0% O_2 (3-hr) 60 ppmv @ 0% O_2 (365 day)	-

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Sasol Chemicals (USA) LLC	LA-0288 PSD-LA-778 (5/23/2014) (GTL unit)	HP SH Steam Boilers (EQT 631, 632, & 633) (process gas)	use of gaseous fuel with a sulfur content of no more than 0.005 gr/scf (ann avg)	24.22 lb/hr max (ea) 1.67 tpy annual (ea)	408.40
		Process Heaterr (EQT 690, 691, 692, 751, 752, &753) (process gas)		25.25 lb/hr max (ea) 2.28 tpy annual (ea) 0.0015 lb/MMBtu ann avg	424.80
	LA-0290 PSD-LA-778 (5/23/2014) (GTL unit)	Hot oil heater (EQT 623) (process gas)		12.34 lb/hr 1.12 tpy	171.00
	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	Fractionator feed heaters (EQT 737 & 774) (process gas)		14.89 lb/hr 1.33 tpy	248.70
		DW reactor feed heaters (EQT 738 & 775) (process gas)		3.61 lb/hr 0.30 tpy	56.80
		Base oils DW reactor feed heater (EQT 776) (process gas)		2.09 lb/hr 0.17 tpy	31.00
		HC reactor feed heaters (EQT 736 & 754) (process gas)		4.43 lb/hr 0.38 tpy	70.80
		Process heater (EQT 702) (process gas)		4.61 lb/hr 0.40 tpy	73.80
		Base oils light vacuum feed heater (EQT 777) (process gas)		4.45 lb/hr 0.38 tpy	71.20
		Base oils heavy vacuum feed heater (EQT 778)		0.86 lb/hr 0.05 tpy	10.00
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0301 PSD-LA-779 (5/23/2014)	Utility Steam Boiler Nos. 1-3 (EQTs 967, 968, &969) (process gas)	use of gaseous fuel with a sulfur content of no more than 0.005 gr/scf (ann avg)	1.98 lb/hr max (ea) 10.43 tpy ann max combined	662.00
		Furnace Nos. 1-8 (EQTs 971 - 978) (process gas)		1.92 lb/hr max (ea) 28.08 tpy ann max comb	654.00
	LA-0303 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 1161) (process gas)		14.12 lb/hr 1.29 tpy	240.00
		Reactor feed heater (EQT 1160)		1.06 lb/hr 0.10 tpy	18.00
	LA-0298 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 772) (process gas)		2.33 lb/hr 0.21 tpy	40.00
	LA-0302 PSD-LA-779 (5/23/2014)	Process heat boilers (EQT 1008 & 1009)		4.60 lb/hr 0.37 tpy	78.00
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Lima Refining Co.	OH-0362 P0114527 (12/23/2013)	Crude Distillation Unit II Heater (refinery fuel gas or natural gas)	H2S concentration <= 230 mg/dscm (0.1 gr/dscf) (equiv to 162 ppmvd) or SO2 <= 20 ppmvd @0% xs air(3 hr avg) <= 60ppmvd H2S or SO2, = 8 ppmvd @ 0% xs air (365 day avg)		624.00
		Vacuum unit II heater (refinery fuel gas or natural gas)			102.30
Sinclair Wyoming Refining Co.	WY-0071 MD-12620 (10/15/2012)	581 crude heater (refinery fuel gas)		follow Subpart Ja fuel gas H2S limits	233.00
		583 vacuum heater			64.20
		Naphtha splitter heater			46.30
		Hydrocracker H5 heater			44.90
		#1 HDS heater			33.40
		BSI heater			50.00
BP Exploration (Alaska)	AK-0074 AQ0181CPT 07 (7/29/2011)	Combustion (fuel gas)		1,000 ppmv (H2S)	98.00
Valero Refining - New Orleans, LLC	LA-0213 PSD-LA-619 (M5) (11/17/2009)	Heater F-72-703 (7-81)	fueled by natural gas or refinery fuel gas with H2S <= 100 ppmv (annual average)	-	633.00
		Boilers (2008-10, 2008-11, 2008-40)	fueled by natural gas or refinery fuel gas with H2S <= 100 ppmv (annual average) or process fuel gas with H2S <= 10 ppmv (annual average)	-	715.00 ea
		Boilers (94-43 & 94-45)	use of pipeline quality natural gas or refinery fuel gas with a H2S concentration < 100 ppmv (annual average)	9.43 lb/hr max	354.00 ea
		heater 2008-1 (natural gas and process fuel gas)	use natural gas or process fuel gases with H2S concentration < 10 ppmv (ann avg)		36.00
		heater 2008-2			880.00
		heater 2008-3			641.00
		heater 2008-4			108.00
		heater 2008-5			123.00
		heater 2008-6			803.00
		heater 2008-7			122.00
		heater 2008-8			803.00
		heater 2008-9			122.00
		heater 94-21			48.00
		heater 94-29			75.00
		heater/reboiler 6-81			135.00
		heater/reboiler 2004-1			86.00
		heater/reboiler 2004-2			24.00
		heater/reboiler 2004-3			52.00
		heater/reboiler 2004-4			86.00
		heater/reboiler 2004-7			885.00
		heater/reboiler 2004-8			885.00
		heater/reboiler 2005-1			1,274.00
		heater/reboiler 2005-2			744.00
		heater/reboiler 2005-3			555.00
		heater/reboiler 2005-8			100.00
		heater/reboiler 2005-9			83.00
		heater/reboiler 2005-10			336.00
		heater/reboiler 2005-22			261.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
		heater/reboiler 2005-23			100.00
		heater/reboiler 2005-24			83.00
		heater/reboiler 2005-25			336.00
		CPF heater H-39-03			68.00
		CPF heater H-39-02			90.00
		DHT heater 4-81			70.00
		DHT heater 5-81			70.00
The Louisiana determination of good combustion practices as BACT is not considered applicable because IDEM finds that the operating permit does not incorporate monitoring and record keeping conditions that demonstrate compliance with the BACT requirement.					
Sunoco, Inc.	OH-0308 04-01447 (2/23/2009)	Boiler (2) (refinery process gas, natural gas, residual #6 oil, and CO from FCCU)		9.15 lb/hr ea 40.60 tpy ea 0.0270 lb/MMBtu operating w/o FCCU	374.00
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Boiler (natural gas and tail gas)	"good combustion practice"	2.00 lb/hr (3 hr avg) 8.9 tpy 0.60 lb/MMSCF	1200.00
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Citgo Petroleum Co.	LA-0234 PSD-LA-691(M1) (1/26/2007)	3(XXXIV)7-201 furnace B-201	low sulfur concentration in the fuel gas 475 ppm max 218.4 ppm avg	5.08 lb/hr	56.90
		3(XXXIV)7-202 furnace B-202		5.08 lb/hr	56.90
		3(XXXIV)7-101 furnace B-101		5.08 lb/hr	62.80
		3(XXXIV)7-102 furnace B-102		5.08 lb/hr	62.80
		3(XXXIV)7-103 reboiler B-103		3.10 lb/hr	50.00
		3(XXXIV)7-203 reboiler B-203		3.10 lb/hr	50.00

Notes:
1. *Good combustion practices shall include installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, and periodic tuneups that are required for units subject to 40 CFR 63, Subpart DDDDD.*

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3, the Best Available Control Technology (PSD BACT) for SO_2 for the fuel combustion units listed in the table below shall be as follows:

Description	Unit ID
Coal dryer heater	EU-1007
Feed heater	EU-2001
Treat gas heater	EU-2002
Vacuum column feed heater	EU-2003
Fractionator heater	EU-2004
Package boiler	EU-6000

(a) The units shall burn only natural gas and process off-gas.

(b) The average sulfur content of the fuel gas combusted shall not exceed 0.005 gr/scf per twelve (12) consecutive month period with compliance determined at the end of each month.

(c) SO_2 emissions shall not exceed:

SO_2 Emission Limitations	
Unit ID	**tpy**
EU-1007	0.35
EU-2001	0.80
EU-2002	0.33
EU-2003	0.06
EU-2004	0.97
EU-6000	0.42

(d) The units shall use good combustion practices. Good combustion practices shall include installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, on each fuel gas combustion unit.

NOx

Step 1: Identify Potential Control Technologies

NOx emissions can be controlled with the following control technologies:

Post-combustion controls:

(1) Selective Catalytic Reduction (SCR)
(2) Selective Non-Catalytic Reduction (SNCR)

Combustion controls:
(3) Low NOx Burner (LNB)/Ultra low-Nox burner (ULNB)
(4) Flue Gas Recirculation (FGR)
(5) Good Combustion Practices

Selective Catalytic Reduction (SCR)
Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to water and N_2. Under optimal conditions, SCR has a removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas window ranging from 480°F to 800°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. In this particular service, the minimum target temperature is approximately 750°F. Temperatures below the optimum decrease catalyst activity and allow ammonia to slip through; above the optimum range, ammonia will oxidize to form additional NOx. Flue gas temperatures for the process fuel gas-fired units range generally from 400°F to 525°F, with one unit (EU-2003) expected to operate at 800°F. Because of the non-optimum temperatures, IDEM assigns a low control efficiency to SCR in this application. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH_3:NOx because variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Selective Non-Catalytic Reduction (SNCR)
With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2000°F, without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction.

At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of competing reactions for the direct oxidation of ammonia that forms NOx becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_X control performance requires that the furnace exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range and steady operation within that temperature window.

Low NOx Burners (LNB)
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible.

Flue Gas Recirculation (FGR)
Recirculating a portion of the flue gas to the combustion zone can lower the peak flame temperature and result in reduced thermal NOx production. The flue gas recirculation (FGR) can be highly effective technique for lowering NOx emissions from burners and it's relatively inexpensive to apply. FGR lowers NOx emissions in two ways; the cooler, relatively inert, recirculated flue gases act as heat sink, absorbing heat from the flame and lowering peak flame temperatures and when mixed with the combustion air, recirculated flue gases lower the average oxygen content of the air, starving the NOx-forming reactions for one of the needed ingredients.

Good Combustion Practices
Good combustion practices are a form of preventive controls that may have only a small effect on pollutant formation except in combination with other controls. Some principles of good combustion practice are taken as incorporated at the equipment design stage, such as proper design of burners and firebox components and ensuring adequate residence time. Other principles, such as minimizing air infiltration and maintaining equipment in accordance with a manufacturer's specification, may be taken as incorporated into the preventive maintenance plan for a unit. The element of good combustion practices that may have the most direct effect, and that may be considered as a control technology, is the control of the fuel-to-air combustion ratio, which can be achieved manually through tuneups as required by the NESHAP, 40 CFR 63, Subpart DDDDD or through control equipment such as an oxygen trim system.

Step 2: Eliminate Technically Infeasible Options:

Technology	BACT Evaluation
Selective Catalytic Reduction (SCR) Technically Feasible – **Yes**	Selective Catalytic Reduction (SCR) is technically feasible.

Technology	BACT Evaluation
Selective Non-Catalytic Reduction (SNCR) Technically Feasible – **No**	Riverview will operate at a wide range of load levels, with lower levels potentially unable to provide a temperature profile that maintains the range needed for effective control for sufficient residence time to achieve proper control. Some ammonia will be emitted. The combustion units used at Riverview combust a combination of gaseous fuels that are proportionally variable over relatively short time periods and results in short term NOx loading variations. This variability woks against the limited temperature flexibility and difficulty of SNCR in adjusting to short term changes maintaining consistent NOx control during operation of these units. For these reasons, the SNCR is technically infeasible.
Low NOx Burner (LNB) Technically Feasible - **Yes**	LNB/ULNB is technically feasible.
Flue Gas Recirculation (FGR) Technically Feasible – **Yes**	Flue Gas Recirculation (FGR) is technically feasible.
Good Combustion Practices Technically Feasible – **Yes**	Good Combustion Practices are technically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Control Option	Expected Control Efficiency
LNB/ULNB	40-85%
SCR	70%-90%
SNCR	30%-50%
FGR	15%-50%
Good combustion practices	not determined

Step 4: Evaluate the Most Effective Controls and Document the Results

Review of similar sources found in the RBLC database does not identify any cases where good combustion practices were incorporated into a determination of BACT for NOx. The following tables summarize other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Combustion Units (<100 MMBtu/hr) - NOx

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-1007 Coal milling and drying heater*	*ULNB (≤0.030 lb NOx/MMBtu)*	*1.67 lb/hr*	*55.80*
		EU-2002 Treat gas heater		*1.58 lb/hr*	*52.80*
		EU-2003 Vacuum column feed heater		*0.27 lb/hr*	*9.00*
		EU-6000 Boiler		*2.06 lb/hr*	*68.50*
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Coker Unit heater and #2 Hydrogen Unit heater	-	0.03 lb/MMBtu	-
Holly Refinery & Marketing-Tulsa LLC	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	Process heaters	ULNB	0.030 lb/MMBtu	10.00 25.00 42.00 50.00
Holly Refinery & Marketing-Tulsa LLC	OK-0166 2010-599-C(M-3) (4/20/2015)	Process heater (refinery fuel gas)	UNLB	0.030 lb/MMBtu (3-hr)	76.00
The entries above are the most restrictive limits found on a lb/MMBtu basis and are selected as BACT.					
Indorama Ventures Olefins LLC	LA-0314 PSD-LA-813 (8/3/2016)	Dryer regenerator heater-005	ULNB, good combustion practices	0.060 lb/MMBtu (3, 1-hr test avg)	29.00
This source is in SIC code 2821, not 2911 like the proposed source. Therefore this entry may not represent BACT for the proposed source.					
Equistar Chemicals LP	LA-0295 PSD-LA-806 (7/12/2016)	Firetube boilers Nos. 1 & 2 (EQT 324 &325)	FGR, good combustion practices	2.75 lb/hr max *(equiv to 0.04 lb/MMBtu)* 30 ppmvd @ 3% O2 (ann avg)	63.00
This source is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Louisiana determination of good combustion practices as BACT is not considered applicable because IDEM finds that the operating permits do not incorporate monitoring and record keeping conditions that demonstrate compliance with the BACT requirement.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Sasol Chemicals (USA) LLC	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	DW reactor feed heaters (EQT 738 & 775) (process gas)	ULNB	2.30 lb/hr 7.87 tpy 0.038 lb/MMBtu	56.80
		Base oils DW reactor feed heater (EQT 776) (process gas)		1.35 lb/hr 4.30 tpy 0.038 lb/MMBtu	31.00
		HC reactor feed heaters (EQT 736 & 754) (process gas)		2.86 lb/hr 9.82 tpy 0.038 lb/MMBtu	70.80
		Process heater (EQT 702) (process gas)		2.98 lb/hr 10.23 tpy 0.038 lb/MMBtu	73.80
		Base oils light vacuum feed heater (EQT 777) (process gas)		2.88 lb/hr 9.87 tpy 0.038 lb/MMBtu	71.20
		Base oils heavy vacuum feed heater (EQT 778)		0.55 lb/hr 1.39 tpy 0.038 lb/MMBtu	10.00
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Reactor feed heater (EQT 1160)	ULNB	0.68 lb/hr 2.50 tpy 0.038 lb/MMBtu	18.00
	LA-0298 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 772) (process gas)		1.50 lb/hr 5.49 tpy 0.038 lb/MMBtu	40.00
	LA-0302 PSD-LA-779 (5/23/2014)	Process heat boilers (EQT 1008 & 1009)		2.97 lb/hr 9.55 tpy 0.038 lb/MMBtu	78.00
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Diamond Shamrock Refining Co, LP	TX-0720 9708, PSDTX861M 3 (12/20/2013)	Vacuum heater	LNB	0.035 lb/MMBtu	88.00
		Naphtha hydrotreater charge heater		0.038 lb/MMBtu	33.30
Sinclair Wyoming Refining Co.	WY-0071 MD-12620 (10/15/2012)	583 vacuum heater	ULNB	1.90 lb/hr 0.030 lb/MMBtu (3-hr avg)	64.20
		Naphtha splitter heater		1.60 lb/hr (3-hr avg) 7.1 tpy 0.035 lb/MMBtu (3-hr avg)	46.30
		Hydrocracker H5 heater		1.60 lb/hr (3-hr avg) 0.0350 lb/MMBtu (3-hr avg)	44.90
		#1 HDS heater		1.20 lb/hr (3-hr avg) 0.0350 lb/MMBtu (3-hr avg)	33.40
		BSI heater		1.30 lb/hr (3-hr avg) 5.50 tpy 0.025 lb/MMBtu (3-hr avg)	50.00
The BSI heater was never constructed and never tested, therefore the unit is not considered as establishing BACT.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-1 (natural gas and process fuel gas)	ULNB	0.040 lb/MMBtu (3, 1-hr test avg, air preheater) 0.030 lb/MMBtu (3, 1-hr test avg)	36.00
		heater 94-21	ULNB	not available	48.00
		heater 94-29	ULNB	not available	75.00
		heater/reboiler 2004-1	ULNB	0.040 lb/MMBtu (3, 1-hr test avg)	86.00
		heater/reboiler 2004-2			24.00
		heater/reboiler 2004-3			52.00
		heater/reboiler 2004-4			86.00
		heater/reboiler 2005-8			100.00
		heater/reboiler 2005-9			83.00
		heater/reboiler 2005-23			100.00
		heater/reboiler 2005-24			83.00
		CPF heater H-39-03	LNB	0.050 lb/MMBtu (3, 1-hr test avg)	68.00
		CPF heater H-39-02			90.00
		DHT heater 4-81	LNB	0.080 lb/MMBtu (3, 1-hr test avg)	70.00
		DHT heater 5-81			70.00
	LA-0265 PSD-LA-619(M7) (10/2/2012)	Boiler 401-F (refinery gas)	ULNB	0.040 lb/MMBtu	99.00
Medicine Bow Fuel & Power	WY-0066 CT-5873 (3/4/2009)	Auxiliary boiler (syngas)	LNB	3.20 lb/hr 14.20 tpy 0.050 lb/MMBtu	66.00
		HGT reactor charge heater		0.10 lb/hr 0.50 tpy 0.050 lb/MMBtu	2.22
Facility was not built and limitations were never tested, therefore this source is not considered in establishing BACT.					
Conoco Phillips	OK-0136 2007-042-C PSD (2/9/2009)	NH-5 new no. 1 CTU tar stripper heater (refinery gas)	ULNB, 0.03 lb/MMBtu	2.94 lb/hr (365 day avg) 12.90 tpy (365 day avg)	98.00
		NH-3 new no. 4 CTU vacuum heater		1.39 lb/hr (365 day avg) 5.90 tpy (365 day avg)	45.00
Sunoco Inc (R&M)	PA-0256 06144 (1/29/2008)	IH-5 heater (refinery fuel gas)	ULNB (BACT & LAER)	8.60 tpy (365 ttl) 0.02 lb.MMBtu (3, 1-hr test)	98.00
This entry is LAER so it is not considered as establishing BACT.					

Notes:
1. tpy - tons per twelve (12) consecutive months

Combustion Units (>100 MMBtu/hr) - NOx

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-2001 Feed heater*	*ULNB (≤0.030 lb NOx/MMBtu)*	*3.85 lb/hr*	*128.40*
		EU-2004 Fractionator heater		*4.68 lb/hr*	*156.00*
Sinclair Wyoming Refining Co.	WY-0071 MD-12620 (10/15/2012)	581 crude heater (refinery fuel gas)	ULNB	7.00 lb/hr (3-hr avg) 0.030 lb/MMBtu (3-hr avg)	233.00
Holly Refinery & Marketing-Tulsa LLC	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	CDU atmospheric tower heater (refinery fuel gas)	ULNB	0.030 lb/MMBtu	248.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
	OK-0170 2012-1062-C(M-6) (11/12/2015)	Process heater (H-205) (refinery fuel gas)			100.00
The entries above are the most restrictive limits found on a lb/MMBtu basis and are selected as BACT.					
Phillips 66 Co.	LA-0283 PSD-LA-696(M-3) (8/14/2015)	294-H-1 (EQT0017) (fuel gas)	ULNB w/ internal FGR	10.08 lb/hr 24.53 tpy 0.040 lb/MMBtu (ann avg)	168.00
M&G Resins USA LLC	TX-0671 108446/PSD TX1352 (12/1/2014)	Heat transfer fluid heaters (natural gas, biogas, and process waste gas)	SCR	12.40 tpy 0.020 lb/MMBtu	141.82 ea
This source is in SIC code 2821, not 2911 like the proposed source. Therefore this entry may not represent BACT for the proposed source.					
Sasol Chemicals (USA) LLC	LA-0290 PSD-LA-778 (5/23/2014) (GTL unit)	Hot oil heater (process gas)	ULNB	7.97 lb/hr 29.09 tpy 0.038 lb/MMBtu	171.00
	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	Fractionator feed heaters (EQT 737 & 774) (process gas)		9.62 lb/hr 34.49 tpy 0.038 lb/MMBtu	248.70
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 1161) (process gas)	ULNB	9.12 lb/hr 33.29 tpy 0.038 lb/MMBtu	240.00
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries may not represent BACT for the proposed source.					
Valero Energy Corp	DE-0020 AQM-003/00016 (2/26/2010)	Crude unit vacuum heater 21-H-2	SCR (RACT)	20.00 lb/hr (24 hr avg) 0.040 lb/MMBtu (3hr avg)	240.00
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-4 (refinery fuel gas)	ULNB	0.040 lb/MMBtu (3, 1-hr test avg, air preheater) 0.030 lb/MMBtu (3, 1-hr test avg)	108.00
		heater 2008-5			123.00
		heater 2008-7			122.00
		heater 2008-9			122.00
		heater/reboiler 6-81		0.040 lb/MMBtu (3, 1-hr test avg)	135.00
Shintech Louisiana LLC	LA-0204 PSD-LA-709(M-1) (2/27/2009)	Boilers A & B	LNB & FGR	0.040 lb/MMBtu	250 ea
		Boilers C & D			
Conoco Phillips	OK-0136 2007-042-C PSD (2/9/2009)	NH-1 new naphtha splitter reboiler	ULNB, 0.03 lb/MMBtu	3.94 lb/hr (365 day avg) 17.30 tpy (365 day avg)	131.00
		NH-4 new no. 1 CTU crude heater		3.37 lb/hr (365 day avg) 16.40 tpy (365 day avg)	125.00

Notes:
1. *tpy - tons per twelve (12) consecutive months*

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 the Best Available Control Technology (PSD BACT), shall be the following:

(a) The units shall burn only natural gas and process off-gas.

(b) The units shall use ultra-low-NOx burners.

(c) NOx emissions shall not exceed:

Emission Limitations		
Unit ID	lb/MMBtu	lb/hr
EU-1007	0.030	1.67
EU-2001	0.030	3.85
EU-2002	0.030	1.58
EU-2003	0.030	0.27
EU-2004	0.030	4.68
EU-6000	0.030	2.06

VOC

Step 1: Identify Potential Control Technologies

VOC emissions can be controlled with the following control technologies:

Post-combustion controls:

(1) Thermal Oxidation
(2) Catalytic Oxidation
(3) Flares

Combustion controls:

(4) Good Combustion Practices

Post-combustion controls
Post-combustion controls identified for natural gas combustion units all include systems that supply energy to destroy pollutants through addition of more fuel.

Good Combustion Practices
Good combustion practices are a form of preventive controls that may have only a small effect on pollutant formation except in combination with other controls. Some principles of good combustion practice are taken as incorporated at the equipment design stage, such as proper design of burners and firebox components and ensuring adequate residence time. Other principles, such as minimizing air infiltration and maintaining equipment in accordance with a manufacturer's specification, may be taken as incorporated into the preventive maintenance plan for a unit. The element of good combustion practices that may have the most direct effect, and that may be considered as a control technology, is the control of the fuel-to-air combustion ratio, which can be achieved manually through tuneups as required by the NESHAP, 40 CFR 63, Subpart DDDDD or through control equipment such as an oxygen trim system.

Step 2: Eliminate Technically Infeasible Options

VOC emissions from boilers/heaters are the result of incomplete fuel combustion. A search of the USEPA's RACT/BACT/LAER Clearinghouse indicates the use of good combustion practice for gas-fired combustion units is the most-commonly cited control for VOC emissions. Natural gas combustion is already efficient. It is possible to achieve VOC reductions from an add-on control device; however, any add-on oxidation control technology would not be cost effective since the VOC concentration in these units is relatively low and supplemental fuel cost would be prohibitive.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

Review of similar sources found in the RBLC database does not identify any cases where good combustion practices were incorporated into a determination of BACT for VOC. The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Combustion Units (<100 MMBtu/hr) - VOC

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-1007 Coal milling and drying heater*	-	*0.30 lb/hr 0.0054 lb/MMBtu*	*55.80*
		EU-2002 Treat gas heater		*0.29 lb/hr 0.0054 lb/MMBtu*	*52.80*
		EU-2003 Vacuum column feed heater		*0.05 lb/hr 0.0054 lb/MMBtu*	*9.00*
		EU-6000 Boiler		*0.37 lb/hr 0.0054 lb/MMBtu*	*68.50*
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-1 (natural gas and process fuel gas)	comply with 40 CFR 60, Subparts NNN and RRR	-	36.00
		heater 94-21	gas fuel, good combustion practices	-	48.00
		heater 94-29			75.00
		heater/reboiler 2004-1			86.00
		heater/reboiler 2004-2			24.00
		heater/reboiler 2004-3			52.00
		heater/reboiler 2004-4			86.00
		heater/reboiler 2005-8			100.00
		heater/reboiler 2005-9			83.00
		heater/reboiler 2005-23			100.00
		heater/reboiler 2005-24			83.00
		CPF heater H-39-03		0.0054 lb/MMBtu	68.00
		CPF heater H-39-02			90.00
		DHT heater 4-81		-	70.00
		DHT heater 5-81			70.00
The entries above are the most restrictive limits found on a lb/MMBtu basis and are selected as BACT. Louisiana determinations of good combustion practices as BACT are not considered applicable because IDEM finds that operating permit do not incorporate monitoring and record keeping conditions that demonstrate compliance with the BACT requirement.					
Indorama Ventures Olefins LLC	LA-0314 PSD-LA-813 (8/3/2016)	Dryer regenerator heater-005	good combustion practices	0.0054 lb/MMBtu	29.00
This source is in SIC code 2821, not 2911 like the proposed source. Therefore the entry does not represent BACT for the proposed source.					
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Coker Unit heater, #2 Hydrogen Unit heater, two existing Coker Unit heaters, Vacuum Unit heater	-	0.005 lb/MMBtu	-
This entry in RBLC is labeled as a draft determination, therefore it is not considered to establish BACT for the proposed source.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Sasol Chemicals (USA) LLC	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	DW reactor feed heaters (EQT 738 & 775) (process gas)	Good combustion practices, 40 CFR 63, Subpart DDDDD tuneups	0.33 lb/hr 1.12 tpy 0.0054 lb/MMBtu	56.80
		Base oils DW reactor feed heater (EQT 776) (process gas)		0.19 lb/hr 0.61 tpy 0.0054 lb/MMBtu	31.00
		HC reactor feed heaters (EQT 736 & 754) (process gas)		0.41 lb/hr 1.39 tpy 0.0054 lb/MMBtu	70.80
		Process heater (EQT 702) (process gas)		0.42 lb/hr 1.45 tpy 0.0054 lb/MMBtu	73.80
		Base oils light vacuum feed heater (EQT 777) (process gas)		0.41 lb/hr 1.40 tpy 0.0054 lb/MMbtu	71.20
		Base oils heavy vacuum feed heater (EQT 778)		0.08 lb/hr 0.20 tpy 0.0054 lb/MMBtu	10.00
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries do not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Reactor feed heater (EQT 1160)	Good combustion practices, applicable provisions of 40 CFR 63, Subpart DDDDD	0.10 lb/hr 0.35 tpy 0.0054 lb/MMBtu	18.00
	LA-0298 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 772) (process gas)		0.21 lb/hr 0.78 tpy 0.0054 lb/MMBtu	40.00
	LA-0302 PSD-LA-779 (5/23/2014)	Process heat boilers (EQT 1008 & 1009)		0.42 lb/hr (ea) 1.36 tpy (comb)	78.00
Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries do not represent BACT for the proposed source.					

Notes:
1. *tpy - tons per twelve (12) consecutive months*

Combustion Units (>100 MMBtu/hr) - VOC

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-2001 Feed heater*	-	*0.69 lb/hr 0.0054 lb/MMBtu*	*128.40*
		EU-2004 Fractionator heater		*0.84 lb/hr 0.0054 lb/MMBtu*	*156.00*
Phillips 66 Co.	LA-0283 PSD-LA-696(M-3) (8/14/2015)	Low sulfur gasoline feed heater no. 1, 294-H-1 (EQT0017) (fuel gas)	Good combustion practices	0.91 lb/hr 3.31 tpy *(equivalent to 0.0054 lb/MMBtu)*	168.00
The entries above are the most restrictive limits found on a lb/MMBtu basis and are selected as BACT. Louisiana determinations of good combustion practices as BACT are not considered applicable because IDEM finds that operating permits do not incorporate monitoring and record keeping conditions that demonstrate compliance with the BACT requirement.					
M&G Resins USA LLC	TX-0671 108446/PSD TX1352 (12/1/2014)	Heat transfer fluid heaters (natural gas, biogas, and process waste gas)	fuel gas firing	3.35 tpy 0.0054 lb/MMBtu	141.82 ea
This source is in SIC code 2821, not 2911 like the proposed source. Therefore the entry does not represent BACT for the proposed source.					

<table>
<tr><th>Facility - County, State</th><th>RBLC ID / Permit # (Issuance Date)</th><th>Process (All natural gas-fired unless otherwise noted)</th><th>Control</th><th>BACT</th><th>Rating (MMBtu/hr)</th></tr>
<tr><td rowspan="4">Sasol Chemicals (USA) LLC</td><td>LA-0290
PSD-LA-778
(5/23/2014)
(GTL unit)</td><td>Hot oil heater
(process gas)</td><td rowspan="2">Good combustion practices, 40 CFR 63, Subpart DDDDD tuneups</td><td>1.13 lb/hr
4.13 tpy
0.0054 lb/MMBtu</td><td>171.00</td></tr>
<tr><td>LA-0291
PSD-LA-778
(5/23/2014)
(GTL unit)</td><td>Fractionator feed heaters (EQT 737 & 774)
(process gas)</td><td>1.37 lb/hr
4.89 tpy
0.0054 lb/MMBtu</td><td>248.70</td></tr>
<tr><td colspan="5">Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.</td></tr>
<tr><td>LA-0303
PSD-LA-779
(5/23/2014)</td><td>Hot oil heater (EQT 1161)
(process gas)</td><td>Good combustion practices, applicable provisions of 40 CFR 63, Subpart DDDDD</td><td>1.29 lb/hr
4.72 tpy
0.0054 lb/MMBtu</td><td>240.00</td></tr>
<tr><td colspan="6">Sasol complex is in SIC code 2869, not 2911 like the proposed source. Therefore these entries do not represent BACT for the proposed source.</td></tr>
<tr><td rowspan="5">Valero Refining-New Orleans LLC</td><td rowspan="5">LA-0213
PSD-LA-619(M5)
(11/17/2009)</td><td>heater 2008-4
(refinery fuel gas)</td><td rowspan="4">comply with 40 CFR 60, Subparts NNN and RRR</td><td rowspan="5">-</td><td>108.00</td></tr>
<tr><td>heater 2008-5</td><td>123.00</td></tr>
<tr><td>heater 2008-7</td><td>122.00</td></tr>
<tr><td>heater 2008-9</td><td>122.00</td></tr>
<tr><td>heater/reboiler 6-81</td><td>gas fuel, good combustion practices</td><td>135.00</td></tr>
<tr><td colspan="6">Louisiana determination of good combustion practices as BACT is not considered applicable because IDEM finds that the operating permits do not incorporate monitoring and record keeping conditions that demonstrate compliance with the BACT requirement.</td></tr>
</table>

Notes:
1. tpy - tons per twelve (12) consecutive months

Step 5: Select BACT

Pursuant to 326 IAC 2-2 (PSD BACT), IDEM has established the following BACT:

BACT shall be the following:

(a) The units shall burn only natural gas and process off-gas.

(b) VOC emissions shall not exceed:

Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
EU-1007	0.0054	0.30
EU-2001	0.0054	0.69
EU-2002	0.0054	0.29
EU-2003	0.0054	0.05
EU-2004	0.0054	0.84
EU-6000	0.0054	0.37

CO

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. CO control technologies include:

Post-combustion controls:

(1) Regenerative thermal oxidation;
(2) Catalytic oxidation;
(3) Flares

Combustion controls:

(4) Good Combustion Practices

Good Combustion Practices
Good combustion practices are a form of preventive controls that may have only a small effect on pollutant formation except in combination with other controls. Some principles of good combustion practice are taken as incorporated at the equipment design stage, such as proper design of burners and firebox components and ensuring adequate residence time. Other principles, such as minimizing air infiltration and maintaining equipment in accordance with a manufacturer's specification, may be taken as incorporated into the preventive maintenance plan for a unit. The element of good combustion practices that may have the most direct effect, and that may be considered as a control technology, is the control of the fuel-to-air combustion ratio, which can be achieved manually through tuneups as required by the NESHAP, 40 CFR 63, Subpart DDDDD or through control equipment such as an oxygen trim system.

Step 2: Eliminate Technically Infeasible Options

Carbon monoxide emissions from boilers and heaters are the result of incomplete fuel combustion. While post-combustion control of CO emissions from an external combustion process may be possible in a physical sense, no demonstrated application of post-combustion control can be found. The EPA Air Pollution Control Cost Manual, 6th ed., (EPA/452/B-02-001, January 2002) has no information about controls for CO. Earlier references, such as Control Techniques for Carbon Monoxide Emissions (EPA-450/3-79-006, June 1979) offer no information about CO controls other than good combustion practices.

One very early reference, Control Techniques for Carbon Monoxide Emissions from Stationary Sources (AP-65, March 1970), notes that "The sources of CO in a petroleum refinery include: catalyst regeneration, coking operations, blanketing gas generators, flares, boilers, and process heaters. Only moving-bed catalyst regenerators and fluid cokers emit significant amounts of CO." The only control AP-65 suggests for CO in these processes, which are not found at Riverview Energy Corporation, are waste heat CO boilers that required a coke-burning rate of 18,000 pounds per hour for a reasonable payout.

In the absence of demonstrated success, post-combustion controls for CO such as RTO's, catalytic oxidation, and flares are considered technically infeasible. A search of the USEPA's RACT/BACT/LAER Clearinghouse indicates the use of good combustion practice and engineering design for gas-fired combustion units is the best control for CO emissions.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary. Good Combustion Practices are a feasible option.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

<u>Combustion Units (<100 MMBtu/hr) - CO</u>

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-1007 Coal milling and drying heater*	*Good combustion practices*	*2.04 lb/hr 0.0365 lb/MMBtu*	*55.80*
		EU-2002 Treat gas heater		*1.93 lb/hr 0.0365 lb/MMBtu*	*52.80*
		EU-2003 Vacuum column feed heater		*0.33 lb/hr 0.0365 lb/MMBtu*	*9.00*
		EU-6000 Boiler		*2.50 lb/hr 0.0365 lb/MMBtu*	*68.50*
The source has proposed a limit of 0.0365 lb CO/MMBtu, which is more restrictive than the limits established for other sources in SIC code 2911. Therefore, this has been determined to be BACT.					
Conoco Phillips	OK-0136 2007-042-C PSD (2/9/2009)	NH-5 new no. 1 CTU tar stripper heater (refinery gas)	ULNB, good combustion practices	3.92 lb/hr 17.2 tpy 0.04 lb/MMBtu	98.00
		NH-3 new no. 4 CTU vacuum heater		1.80 lb/hr 7.90 tpy 0.04 lb/MMBtu	45.00
This entry includes the most restrictive work practices. Therefore, this has been determined to be BACT.					
Holly Refinery & Marketing-Tulsa LLC	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	Process heaters	0.040 lb/MMBtu	-	10.00 25.00 42.00 50.00
Holly Refinery & Marketing-Tulsa LLC	OK-0166 2010-599-C(M-3) (4/20/2015)	Process heater (refinery fuel gas)	0.040 lb/MMBtu	-	76.00
Sinclair Wyoming Refining Co.	WY-0071 MD-12620 (10/15/2012)	583 vacuum heater	Good combustion practices	2.60 lb/hr 0.040lb/MMBtu	64.20
		Naphtha splitter heater		1.90 lb/hr 0.040lb/MMBtu	46.30
		Hydrocracker H5 heater		1.80 lb/hr 0.040lb/MMBtu	44.90
		#1 HDS heater		1.30 lb/hr 0.040lb/MMBtu	33.40
		BSI heater		2.00 lb/hr 8.80 tpy 0.040lb/MMBtu	50.00
The BSI heater was never constructed and never tested, therefore the unit is not considered as establishing BACT.					
ExxonMobil Oil Corp.	TX-0832 PSDTX768M 1, PSDTX799, PSDTX802 (1/9/2018)	F-2001 Kero HDT Charge Heater and F-2002 Kero HDT Stripper Reboiler (natural gas/refinery gas)	good combustion and use of gaseous fuel	0.074 lb/MMBtu	85.50
		F-3001 Diesel DHDT charge heater & F-3002 diesel DHDT stripper reboiler (natural gas /refinery gas)			66.50
This RBLC entry is labeled as draft, therefore limits are not considered as establishing BACT for the proposed source because the limits have not been tested.					
Indorama Ventures Olefins LLC	LA-0314 PSD-LA-813 (8/3/2016)	Dryer regenerator heater-005	GCP	0.082 lb/MMBtu	29.00
This source is in SIC code 2821, not 2911 like the proposed source. Therefore this entry does not represent BACT for the proposed source.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Sasol Chemicals (USA) LLC	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	DW reactor feed heaters (EQT 738 & 775) (process gas)	GCP	2.15 lb/hr 7.25 tpy 0.035 lb/MMBtu	56.80
		Base oils DW reactor feed heater (EQT 776) (process gas)		1.24 lb/hr 3.96 tpy 0.035 lb/MMBtu	31.00
		HC reactor feed heaters (EQT 736 & 754) (process gas)		2.64 lb/hr 9.04 tpy 0.035 lb/MMBtu	70.80
		Process heater (EQT 702) (process gas)		2.74 lb/hr 9.42 tpy 0.035 lb/MMBtu	73.80
		Base oils light vacuum feed heater (EQT 777) (process gas)		2.65 lb/hr 9.09 tpy 0.035 lb/MMBtu	71.20
		Base oils heavy vacuum feed heater (EQT 778)		0.51 lb/hr 1.28 tpy 0.035 lb/MMBtu	10.00
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries do not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Reactor feed heater (EQT 1160)	GCP	0.63 lb/hr 2.30 tpy 0.035 lb/MMBtu	18.00
	LA-0298 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 772) (process gas)		1.39 lb/hr 5.06 tpy 0.035 lb/MMBtu	40.00
	LA-0302 PSD-LA-779 (5/23/2014)	Process heat boilers (EQT 1008 & 1009)		2.74 lb/hr 8.80 tpy 0.035 lb/MMBtu	78.00
The Sasol complex is in SIC code 2869, therefore these entries are not considered as establishing BACT for the proposed source, which is in SIC code 2911					
Philadelphia Energy Solutions	PA-0299 12195 (2/19/2014)	Unit 865 11H1 htr (refinery fuel gas)	Good combustion practices, annual tuneup 0.0824 lb/MMBtu	7.19 lb/hr	87.30
		Unit 865 11H2 htr		5.29 lb/hr	64.20
		Unit 866 12H1 htr		5.04 lb/hr	61.20
		Unit 868 8H101 htr		4.94 lb/hr	60.0
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-1 (natural gas and process fuel gas)	-	0.080 lb/MMBtu	36.00
		heater 94-21	gaseous fuel, good combustion practices	-	48.00
		heater 94-29			75.00
		heater/reboiler 2004-1	gaseous fuel, good combustion practices	0.080 lb/MMBtu	86.00
		heater/reboiler 2004-2			24.00
		heater/reboiler 2004-3			52.00
		heater/reboiler 2004-4			86.00
		heater/reboiler 2005-8			100.00
		heater/reboiler 2005-9			83.00
		heater/reboiler 2005-23			100.00
		heater/reboiler 2005-24			83.00
		CPF heater H-39-03			68.00
		CPF heater H-39-02			90.00
		DHT heater 4-81			70.00
		DHT heater 5-81			70.00
Medicine Bow Fuel & Power	WY-0066 CT-5873 (3/4/2009)	Auxiliary boiler (syngas)	Good combustion practices	5.4 lb/hr 23.80 tpy 0.080 lb/MMBtu	66.00
		HGT reactor charge heater		0.20 lb/hr 0.80 tpy 0.080 lb/MMBtu	2.22
Facility was not built and limitations were never tested, therefore this source is not considered in establishing BACT.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Louisiana and Wyoming determinations of good combustion practices as BACT are not considered applicable because IDEM finds that the operating permits do not incorporate monitoring and record keeping conditions that demonstrate compliance with the BACT requirement. Oklahoma BACT requirement for good combustion practices is control of excess oxygen, which IDEM considers as requiring the use of oxygen trim systems on each unit. Pennsylvania permit requirements for good combustion practices and any related monitoring or record keeping requirements were not found for review. Texas requirements in the draft determination cited were consistent with Oklahoma.					

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, and periodic tuneups that are required for units subject to 40 CFR 63, Subpart DDDDD.*

Combustion Units (>100 MMBtu/hr) - CO

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-2001 Feed heater*	*Good combustion practices*	*4.69 lb/hr 0.0365 lb/MMBtu*	*128.40*
		EU-2004 Fractionator heater		*5.69 lb/hr 0.0365 lb/MMBtu*	*156.00*
The source has proposed a limit of 0.0365 lb CO/MMBtu, which is more restrictive than the limits established for other sources in SIC code 2911. Therefore, this has been determined to be BACT.					
Holly Refinery & Marketing-Tulsa LLC	OK-0170 2012-1062-C(M-6) (11/12/2015)	Process heater (H-205) (refinery fuel gas)	ULNB, gas fuel	0.040lb/MMBtu	100.00
	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	CDU atmospheric tower heater (refinery fuel gas)			248.00
Philadelphia Energy Solutions	PA-0299 12195 (2/19/2014)	Unit 231 B101 htr (refinery fuel gas)	*Good combustion practices*, annual tuneup 0.0824 lb/MMBtu	8.61 lb/hr	104.50
		Unit 210 H101 htr		15.82 lb/hr	192.00
		NH-1 new naphtha splitter reboiler		5.25 lb/hr 23.00 tpy 0.040 lb/MMBtu	131.00
		NH-4 new no. 1 CTU crude heater		5.00 lb/hr 21.90 tpy 0.040 lb/MMBtu	125.00
Sinclair Wyoming Refining Co.	WY-0071 MD-12620 (10/15/2012)	581 crude heater (refinery fuel gas)	*Good combustion practices*	9.30 lb/hr 0.040lb/MMBtu	233.00
Sasol Chemicals (USA) LLC	LA-0290 PSD-LA-778 (5/23/2014) (GTL unit)	Hot oil heater (EQT 623) (process gas)	*Good combustion practices*, NESHAP 5D	7.34 lb/hr 26.80 tpy 0.035 lb/MMBtu	171.00
	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	Fractionator feed heaters (EQT 737 & 774) (process gas)		8.86 lb/hr 31.70 tpy 0.035 lb/MMBtu	248.70
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries do not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 1161) (process gas)	*Good combustion practices*, NESHAP 5D	8.40 lb/hr 30.66 tpy 0.035 lb/MMBtu	240.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
The Sasol complex is in SIC code 2869, therefore these entries are not considered as establishing BACT for the proposed source, which is in SIC code 2911					
Valero Refining-New Orleans LLC	LA-0213 PSD-LA-619(M5) (11/17/2009)	heater 2008-4 (refinery fuel gas)	gaseous fuel, *good combustion practices*	0.080 lb/MMBtu	108.00
		heater 2008-5			123.00
		heater 2008-7			122.00
		heater 2008-9			122.00
		heater/reboiler 6-81			135.00
Shintech Louisiana LLC	LA-0204 PSD-LA-709(M-1) (2/27/2009)	Boilers A & B	*Good combustion practices*, natural gas fuel	0.036 lb/MMBtu	250.00
		Boilers C & D			
This source is in SIC code 2821, therefore this entry is not considered as establishing BACT for the proposed source, which is in SIC code 2911					
Louisiana and Wyoming determinations of good combustion practices as BACT are not considered applicable because IDEM finds that the operating permits do not incorporate monitoring and record keeping conditions that demonstrate compliance with the BACT requirement. Pennsylvania permit requirements for good combustion practices and any related monitoring or record keeping requirements were not found for review. Pennsylvania requirement for good combustion practices considered as consistent with Oklahoma and Texas requirements cited in the table above for units <100 MMBtu/hr.					

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, and periodic tuneups that are required for units subject to 40 CFR 63, Subpart DDDDD.*

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 the Best Available Control Technology (PSD BACT), shall be the following:

(a) The units shall burn only natural gas and process off-gas.

(b) The units shall use good combustion practices. Good combustion practices shall include the installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, on each fuel gas combustion unit.

(c) CO emissions shall not exceed:

Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
EU-1007	0.0365	2.04
EU-2001	0.0365	4.69
EU-2002	0.0365	1.93
EU-2003	0.0365	0.33
EU-2004	0.0365	5.69
EU-6000	0.0365	2.50

GHGs

Step 1: Identify Potential Control Technologies

(1) Energy efficiency measures
(2) Post-combustion CO_2 capture and sequestration (CCS).

Step 2: Eliminate Technically Infeasible Options

Energy efficiency measures

An opportunity for reducing GHG emissions is to increase the energy efficiency. Because CO_2 emissions are a direct result of the amount of fuel fired (for a given fuel), the more efficient the process, the less fuel that is required and the less greenhouse gas emissions that result. Some energy efficiency measures that may be applied include the following:

Coal Moisture Control
The VCC process requires coal with specific properties in order to operate efficiently. Maintaining tight coal specifications to keep moisture to low levels would reduce energy requirements, and therefore reduce emissions.

General Measures
Some energy efficiency measures are built into combustion units, to the greatest possible extent, at the design stage. These are taken to include specification of refractories and insulating materials, and details of burners, combustion chambers, and heat exchangers. Design for the highest practical energy efficiency may be taken as a universal element of combustion systems because, if for no other reason, of the owner's interest in achieving the maximum energy recovery from the value of the fuel.

Systems to monitor and track performance of critical equipment and processes can help optimize operation. Using this information, research on machinery and equipment can be conducted, as could energy efficiency studies and other measures such as predictive maintenance. Scheduled preventive maintenance and rotation of redundant equipment helps minimize equipment downtime and optimize operation. Training programs appropriate to the functions of operating and maintenance personnel and good housekeeping programs as an element of preventive maintenance planning help decrease energy consumption.

Combustion equipment tune ups that may be required by applicable regulations, such as 40 CFR 63, Subpart DDDDD, contribute to achieving and maintaining the greatest possible level of energy efficiency. Such a requirement for tune ups, if applicable to a fuel gas combustion unit, is incorporated in permit conditions implementing the underlying regulation. Details of tune up requirements may not be included in permit BACT conditions if the requirements are easily found in other sections of a permit.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of energy efficiency is a technically feasible option for the heaters and boiler at this source.

Post-combustion CO_2 capture and sequestration (CCS)
Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams". However, the heaters and boiler at Riverview do not fit into either of these categories. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above quoted examples. However, some guidance specific to medium-sized natural gas boilers appears in its guidance document which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option.

Natural gas combustion heater/boiler exhaust streams have relatively low CO_2 concentrations (6-9% versus 12-15% for coal-boilers and >30% for high concentration industrial gas streams). This means that for a natural gas heater/boiler, a very large volume of gas needs to be treated to recover the CO_2. Additionally, the low concentration and low pressure complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO_2

stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any natural gas combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale.

The CO_2 must be reused or liquefied, transported and stored. Pipelines are the most common. The CO_2 must be compressed to high pressures, which requires considerable energy consumption. At this time, existing infrastructure to support the transportation of CO_2 does not exist. Therefore, transportation of the CO_2 stream would require the construction of a pipeline to the nearest sequestration site.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of post-combustion CO_2 capture is not a technically or economically feasible option for the operations at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Combustion Units - CO_2e

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*EU-1007 Coal milling and drying heater*	*energy efficiency, good combustion practices, and gaseous fuel*	*29,127 tons/yr*	*55.80*
		EU-2001 Feed heater		*67,023 tons/yr*	*128.40*
		EU-2002 Treat gas heater		*27,561 tons/yr*	*52.80*
		EU-2003 Vacuum column feed heater		*4,698 tons/yr*	*9.00*
		EU-2004 Fractionator heater		*81,430 tons/yr*	*156.00*
		EU-6000 Boiler		*35,756 tons/yr*	*68.50*
Production-based limits, e.g., lb/MMBtu or lb/1000 lb steams, cannot be considered as establishing BACT for the proposed source because of differences in fuel heating values and unit efficiencies, and because not all units are steam-generating equipment.					
Exxon Mobil Oil Corp.	TX-0832 PSDTX768M 1, PSDTX799, PSDTX802 (1/9/2018)	F-2001 kero HDT charge heater & F-2002 kero HDT stripper reboilers	stack temp 600°F, good combustion practices	-	85.50
		F-3001 diesel DHDT charge heater and F-3002 diesel DHDT stripper reboiler			66.50
This RBLC entry is labeled as draft, therefore limits are is not considered as establishing BACT for the proposed source because the limits have not been tested.					
Indorama Ventures Olefins LLC	LA-0314 PSD-LA-813 (8/3/2016)	Dryer regenerator heater-005	gas fuel, good combustion practices	-	29.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Holly Refinery & Marketing-Tulsa LLC	OK-0167 2012-1062-C(M-1)PSD (4/20/2015)	Process heaters	gas fuel, energy efficiency	146 lb/MMBtu	10.00
					25.00
					42.00
					50.00
		CDU atmospheric tower heater (refinery fuel gas)			248.00
	OK-0166 2010-599-C(M-3) (4/20/2015)	Process heater (refinery fuel gas)			76.00
	OK-0143 98-014-C(M-19) (3/1/2012)	Natural gas & refinery gas-fired boiler	economizer, microprocessor controls	206 lb CO2e/1000 lb steam (30 day avg)	214.60
Sasol Chemicals (USA) LLC	LA-0290 PSD-LA-778 (5/23/2014) (GTL unit)	Hot oil heater (process gas)	natural gas fuel, good combustion practices	89564 tpy	171.00
	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	DW reactor feed heaters (EQT 738 & 775) (process gas)		34317 tpy (738) 35302 tpy (775)	56.80
		Base oils DW reactor feed heater (EQT 776) (process gas)		22757 tpy	31.00
		HC reactor feed heaters (EQT 736 & 754) (process gas)		43002 tpy (736) 44252 tpy (754)	70.80
		Process heater (EQT 702) (process gas)		61709 tpy	73.80
		Base oils light vacuum feed heater (EQT 777) (process gas)		54353 tpy	71.20
		Base oils heavy vacuum feed heater (EQT 778)		6235 tpy	10.00
		Fractionator feed heaters (EQT 737 & 774) (process gas)		153286 tpy (737) 157892 tpy (774)	248.70
	Sasol GTL project reportedly cancelled in November 2017. Therefore these entries may not represent BACT for the proposed source.				
	LA-0303 PSD-LA-779 (5/23/2014)	Reactor feed heater (EQT 1160)	Good combustion practices	9484 tpy	18.00
		Hot oil heater (EQT 1161) (process gas)		143933 tpy	240.00
	LA-0298 PSD-LA-779 (5/23/2014)	Hot oil heater (EQT 772) (process gas)		16692 tpy	40.00
	LA-0302 PSD-LA-779 (5/23/2014)	Process heat boilers (EQT 1008 & 1009)		69173 tpy (comb)	78.00
The Sasol complex is in SIC code 2869, therefore these entries are not considered as establishing BACT for the proposed source, which is in SIC code 2911					
Lima Refining Co.	OH-0362 P0114527 (12/23/2013)	Vacuum unit II heater	low carbon gaseous fuel, good combustion practices	-	102.30

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process (All natural gas-fired unless otherwise noted)	Control	BACT	Rating (MMBtu/hr)
Louisiana determinations of good combustion practices as BACT are not considered applicable because IDEM finds that the operating permits do not incorporate monitoring and record keeping conditions that demonstrate compliance with the BACT requirement. Oklahoma BACT requirement for microprocessor control is considered as requiring the use of oxygen trim systems on each unit. Ohio requirement for good combustion practices is control of excess oxygen, which IDEM also considers as an oxygen trim system. Texas requirements in the draft determination cited were consistent with Oklahoma and Ohio.					

Notes:
1. *tpy - tons per twelve (12) consecutive months*

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 the Best Available Control Technology (PSD BACT), shall be the following:

(a) The units shall burn only natural gas and process off-gas.

(b) The units shall be designed and operated to achieve the highest practical energy efficiency.

(c) The units shall use good combustion practices. Good combustion practices shall include the installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, on each fuel gas combustion unit.

(d) CO_2e emissions shall not exceed the value of tons per twelve (12) consecutive month period shown in the table below:

Emission Limitations	
Unit ID	**CO_2e Limit**
EU-1007	29,127
EU-2001	67,023
EU-2002	27,561
EU-2003	4,698
EU-2004	81,430
EU-6000	35,756

BACT Analysis
Sulfur Recovery/Tail Gas Treatment Unit (TGTU)

The sulfur recovery process converts H_2S (from the amine regeneration process and sour water stripping process) to elemental sulfur. In this case, the Claus process is used. Feed gases are burned with sufficient air to combust some of the H_2S to promote the Claus reactions. This process creates emissions.

$PM/PM_{10}/PM_{2.5}$

The tail gas treatment units are the expected source and emission point of particulate matter emissions within the sulfur recovery process. Processing steps intended to maximize sulfur production recover sulfur in gas streams in the form of acid gas that is recycled to the start of the Claus train. The mechanism generating particulate matter is the combustion of gas fuel in the tail gas incinerators. The observation about mechanism is consistent with permit actions in other states, e.g., note to condition 10.b)(2)e, Ohio final PTI no. P0111667, BP-Husky Refining LLC, 9/20/2013, RBLC ID No. OH-0357, "The burning of gaseous fuels is the only source of PE from this emissions unit".

Step 1: Identify Potential Control Technologies

$PM/PM_{10}/PM_{2.5}$ emissions can be controlled with the following control technologies:

(1) Good Combustion Practices

Step 2: Eliminate Technically Infeasible Options

A search of the USEPA's RACT/BACT/LAER Clearinghouse indicates the use of good combustion practices is the only control for $PM/PM_{10}/PM_{2.5}$ emissions applied to Claus TGTU incinerators. Good combustion practices are a technically feasible option.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):
Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - $PM/PM_{10}/PM_{2.5}$

<table>
<tr><th>Facility - County, State</th><th>RBLC ID / Permit # (Issuance Date)</th><th>Process</th><th>Control</th><th>BACT</th><th>Throughput (Long tons/day)</th></tr>
<tr><td>Riverview Energy</td><td>Proposed</td><td>Claus SRU TGTU (EU-3001 and EU-3002)</td><td>SRU Tail gas unit with incinerator burner and low-NOx burners,good combustion practices</td><td>PM (filterable):
0.0019 lb/MMBtu
0.10 lb/hr, each
PM10/PM2.5:
0.0074 lb/MMBtu
0.39 lb/hr
(each)
10% opacity</td><td>111
(max, ea)
159
(comb, bottle-necked)</td></tr>
<tr><td>BP Products, North America</td><td>OH-0357
P0111667
(9/20/2013)</td><td>Claus SRU (incinerator)</td><td>None</td><td>PM10:
0.6 lb/hr
1.74 tpy
based on AP-42, 7.6 lb/MMscf
(equivalent to 0.0074 lb/MMBtu)</td><td>120
(32.15 MMBtu/hr)</td></tr>
<tr><td colspan="6">This is the most stringent limit for PM10. Therefore, it has been determined to be BACT for PM10 and PM2.5.</td></tr>
<tr><td>Sunoco</td><td>OH-0308
04-01447
(2/23/2009)</td><td>Sulfur Recovery Unit (new)</td><td>Tail gas treatment units and SRU incinerator thermal oxidizer low-nox burners</td><td>PM10: 1.36 lb/hr and 5.96 tpy (12-month rolling avg.) and 0.08 lb/MMBtu
10% opacity (6-min avg.)</td><td>17
MMBtu/hr</td></tr>
<tr><td colspan="6">This is the most stringent limit for opacity, therefore it has been included in BACT.</td></tr>
<tr><td>Conoco Phillips Co.</td><td>MT-0030
2619-24
(11/19/2008)</td><td>Claus SRU TGTU</td><td>Proper equipment design, good combustion practices and use gaseous fuels</td><td>PM10:
6.26 lb/hr
186.3 lb/day
27.42 tpy</td><td>235</td></tr>
<tr><td colspan="6">This is the most stringent limitation on design and operating practice, therefore it has been included in BACT. The RBLC entry does not include numeric limits on particulate matter, however the PM10 limit shown appears in the permit as applicable after completion of the project for which the permit cited was issued. The referenced permit does not appear to include a definition of "good combustion practices", however the BACT requirement is supported by testing requirements.</td></tr>
<tr><td>CHS McPherson Refinery Inc</td><td>KS-0032
C-13055
(12/12/2015)</td><td>Sulfur Recovery Plant</td><td>ATS units</td><td>PM: 3.67 lb/hr
PM10: 7.76 lb/hr</td><td>-</td></tr>
<tr><td colspan="6">Not considered a representative comparison. PM/PM10 emissions from the sulfur recovery plant at this source are controlled by a mist eliminator. Ammonium thiosulfate (ATS) is produced by reacting elemental sulfur from a Claus system with ammonia, emissions are therefore not representative of a Claus TGTU. Permit cited does not appear to be available on line.</td></tr>
</table>

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Sulfur recovery process units	thermal oxidizer low NOx burners	VE: 20% Opacity PM10: 0.2 lb/hr (0.85 tpy) (AP-42)	23.5 ton/hr
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					

Notes:
1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, and periodic tuneups that are required for units subject to 40 CFR 63, Subpart DDDDD.*

Step 5: Select BACT

IDEM, OAQ has established $PM/PM_{10}/PM_{2.5}$ BACT for TGTUA and TGTUB as:

(a) PM (filterable) emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0019 lb/MMBtu and 0.10 lb/hr, each.

(b) PM_{10} emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0074 lb/MMBtu and 0.39 lb/hr, each.

(c) $PM_{2.5}$ emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0074 lb/MMBtu and 0.39 lb/hr, each.

(d) Opacity shall not exceed ten percent (10%) on a six-minute average.

(e) Incinerators (A-605A and A-605B) shall use good combustion practices. Good combustion practices shall include installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, on each fuel gas combustion unit.

SO_2

Step 1: Identify Potential Control Technologies

The source selected the Claus sulfur recovery process to produce a product for sale from sulfur and its compounds that are found in the coal supply. The review of emissions control processes is therefore limited to options appropriate to Claus process tail gas. Manufacture of a different product for sale, such as ammonium thiosulfate, from elemental sulfur produced in a Claus process is not considered a different control technology, but only additional downstream processing that is not relevant to control of emissions from the sulfur recovery process. Tail gas treatment units (TGTU) are a possible control technology for the Claus process exhaust gas.

Step 2: Eliminate Technically Infeasible Options

A search of the USEPA's RACT/BACT/LAER Clearinghouse indicates that a Claus unit equipped with a TGTU is the most stringent control technology for SO_2 emissions from a Claus SRU. The SCOT (Shell Claus off-gas treating) process named in one RBLC entry is a variant of tail gas treatment considered functionally the same as the process proposed by the source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - SO_2

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners*	*150 ppmv @ 0% O_2 (annual) 167 ppmv @ 0% O_2 (12-hour avg) 26.30 lb/hr (ea)*	*111 (max, ea) 159 (comb, bottle-necked)*
Conoco Phillips Co.	MT-0030 2619-24 (11/19/2008)	Claus SRU TGTU	TGTU	150 ppmv @ 0% O_2 (annual) 167 ppmv @ 0% O_2 (12-hour avg)	235
This is the most stringent limit for SO_2 - considered more restrictive than higher ppmv limits with specified control efficiencies. Therefore, this has been determined to be BACT.					
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Sulfur Recovery Plant	ATS units	90 ppmvd @ 0% O_2 (24 hr avg) SO_2 CEMS	-
Not considered a representative comparison. PM/PM10 emissions from the sulfur recovery plant at this source are controlled by a mist eliminator. Ammonium thiosulfate (ATS) is produced by reacting elemental sulfur from a Claus system with ammonia, emissions are therefore not representative of a Claus TGTU. Permit cited does not appear to be available on line.					
Diamond Shamrock Refining	TX-0720 PSDTX861M3 (12/20/2013)	Sulfur Recovery Unit (SRU)	SCOT technology and tail gas incinerators	99.8% sulfur recovery	Not listed
BP Products, North America	OH-0357 P0111667 (9/20/2013)	Claus SRU	None	250 ppmv 75 tpy (combined all 3)	120 (32.15 MMBtu/hr)
DCP Midstream	TX-0604 676A, PSDTX1246 (11/3/2011)	Tail gas incinerator	-	1521.8 tpy	
Valero Refining	TX-0595 2937, PSDTX1023M2 (8/19/2010)	Sulfur Recovery Unit (SRU)	none	267 lb/hr 19.2 tpy	
Valero Refining	TX-0592 38754, PSDTX324M13 (3/29/2010)	Sulfur Recovery Unit (SRU)	none	761 lb/hr 9.1 tpy	
Valero Energy Corp.	DE-0020 AQM-003/00016 (2/26/2010)	Sulfur Recovery Unit (SRU)	tail gas unit with stack incinerator	250 ppmv @ 2% O2 (12-hr rolling avg.) 122.0 lb/hr (24-hr rolling avg.) 99.99% control	822
Sunoco	OH-0308 04-01447 (2/23/2009)	Sulfur Recovery Unit (existing)	Tail gas treatment units and SRU incinerator for H_2S	0.07 lb/lb sulfur processed 250 ppmv @ 0% excess air (12-hr rolling avg.) SO_2 CEMS (NSPS Subpart J)	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
		Sulfur Recovery Unit (new)	Tail gas treatment units and SRU incinerator thermal oxidizer low-nox burners	9.88 lb/hr 43.28 tpy 250 ppmv @ 0% excess air (12-hr rolling avg.) SO2 CEMS	17 MMBtu/hr
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Sulfur recovery process units	thermal oxidizer low NOx burners	4893.415 lb/hr 142.72 tpy 250 ppmv (subpart Ja)	23.5 ton/hr
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Sunoco	PA-0256 06144 (1/29/2008)	Sulfur Recovery Unit	Tail gas combustion unit	250 ppm 31.72 lb/hr	
Navajo Refining	NM-0050 PSD-NM-195-M25 (12/14/2007)	Sulfur Recovery Unit	Tail gas incinerator	192 ppmv @ 0% O2 (12-hr rolling avg. and 365 day rolling avg.)	
Texstar	TX-0501 6051, PSD-TX-55M3 (7/11/2006)	Tail gas incinerator stack	-	350.0 lb/hr 1095.0 tpy	

Step 5: Select BACT

IDEM, OAQ has established SO_2 BACT for TGTUA and TGTUB as:

(a) The SO_2 emissions from each tail gas treatment unit stack (TGTUA and TGTUB) shall not exceed 150 ppmv @ 0% excess air (on a twelve month rolling average) and shall be less than 167 ppmv @ 0% excess air (on a twelve hour average).

(b) The SO_2 emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 26.30 lb/hr, each.

NOx

NOx is generated from the combustion of fuel gas in the SRU tail gas thermal oxidizer.

Step 1: Identify Potential Control Technologies

As a combustion source, NOx emissions from the TGTU can be controlled with control technologies that are feasible for combustion sources, including:

(1) Selective Catalytic Reduction (SCR)
(2) Selective Non-Catalytic Reduction (SNCR)

Combustion controls:
(3) Low NOx Burner (LNB)/Ultra low-Nox burner (ULNB)
(4) Flue Gas Recirculation (FGR)
(5) Good Combustion Practices

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to water and N_2. Under optimal conditions, SCR has a removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas window ranging from 480°F to 800°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. In this particular service, the minimum target temperature is approximately 750°F. Temperatures below the optimum decrease catalyst activity and allow ammonia to slip through; above the optimum range, ammonia will oxidize to form additional NOx. Flue gas temperatures for the process fuel gas-fired units range generally from 400°F to 525°F, with one unit (EU-2003) expected to operate at 800°F. Because of the non-optimum temperatures, IDEM assigns a low control efficiency to SCR in this application. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH_3:NOx because variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Selective Non-Catalytic Reduction (SNCR)
With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2000°F, without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction.

At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of competing reactions for the direct oxidation of ammonia that forms NOx becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_X control performance requires that the furnace exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range and steady operation within that temperature window.

Low NOx Burners (LNB)
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible.

Flue Gas Recirculation (FGR)
Recirculating a portion of the flue gas to the combustion zone can lower the peak flame temperature and result in reduced thermal NOx production. The flue gas recirculation (FGR) can be highly effective technique for lowering NOx emissions from burners and it's relatively inexpensive to apply. FGR lowers NOx emissions in two ways; the cooler, relatively inert, recirculated flue gases act as heat sink, absorbing heat from the flame and lowering peak flame temperatures and when mixed with the combustion air, recirculated flue gases lower the average oxygen content of the air, starving the NOx-forming reactions for one of the needed ingredients.

Good Combustion Practices

Good combustion practices are a form of preventive controls that may have only a small effect on pollutant formation except in combination with other controls. Some principles of good combustion practice are taken as incorporated at the equipment design stage, such as proper design of burners and firebox components and ensuring adequate residence time. Other principles, such as minimizing air infiltration and maintaining equipment in accordance with a manufacturer's specification, may be taken as incorporated into the preventive maintenance plan for a unit. The element of good combustion practices that may have the most direct effect, and that may be considered as a control technology, is the control of the fuel-to-air combustion ratio, which can be achieved manually through tuneups as required by the NESHAP, 40 CFR 63, Subpart DDDDD or through control equipment such as an oxygen trim system.

Step 2: Eliminate Technically Infeasible Options

Technology	BACT Evaluation
Selective Catalytic Reduction (SCR) Technically Feasible – **No**	TGTU oxidizer exhaust gases may contain SO_2 that would poison reduction catalysts.
Selective Non-Catalytic Reduction (SNCR) Technically Feasible – **No**	TGTU oxidizers may not achieve high enough temperatures for the SNCR reaction and the presence of sulfur may result in unwanted side reactions producing ammoniun sulfur salts rather than the desired NOx reduction reaction.
Low NOx Burner (LNB) Technically Feasible - **Yes**	LNB/ULNB is technically feasible.
Flue Gas Recirculation (FGR) Technically Feasible – **Yes**	Flue Gas Recirculation (FGR) is technically feasible.
Good Combustion Practices Technically Feasible – **Yes**	Good combustion practices are technically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Control Option	Expected Control Efficiency
LNB/ULNB	40-85%
FGR	15%-50%
Good combustion practices	not determined

Step 4: Evaluate the Most Effective Controls and Document the Results

Ultra-low NOx burners are considered to offer higher control efficiency than other post-combustion controls. Review of similar sources found in the RBLC database does not identify any cases where good combustion practices were incorporated into a determination of BACT for NOx. The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - NOx

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners, good combustion practices*	*0.1 lb/MMBtu 5.28 lb/hr, each*	*111 (max, ea) 159 (comb, bottle-necked)*
BP Products, North America	OH-0357 P0111667 (9/20/2013)	Claus SRU	Low NOx burners	4.4 lb/hr 12.76 tpy (0.1 lb/MMBtu)	120 (32.15 MMBtu/hr)
This is the most stringent limit for NOx. Therefore, this has been determined to be BACT.					
Sunoco	OH-0308 04-01447 (2/23/2009)	Sulfur Recovery Unit (new)	Tail gas treatment units and SRU incinerator thermal oxidizer low-NOx burners	2.55 lb/hr 11.17 tpy (12-month rolling avg.) 0.15 lb/MMBtu	17 MMBtu/hr
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Sulfur recovery process units	thermal oxidizer low NOx burners	1224 lb/hr 7.35 tpy	23.5 ton/hr
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Conoco Phillips Co.	MT-0030 2619-24 (11/19/2008)	Claus SRU TGTU	Thermal Oxidizer with low NOx burner	none	235
Texstar	TX-0501 6051, PSD-TX-55M3 (7/11/2006)	Tail gas incinerator stack	-	8.46 lb/hr 37.05 tpy	

Notes:
1. tpy - tons per twelve (12) consecutive months

Step 5: Select BACT

IDEM, OAQ has established NOx BACT for TGTUA and TGTUB as:

(a) The tail gas treatment units (TGTUA and TGTUB) shall each use low-NOx burners.

(b) NOx emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.10 lb/MMBtu and 5.28 lb/hr, each.

VOC

In normal operations, the heat demand of the sulfur recovery process is supplied by combustion of hydrogen sulfide in the acid gas furnace. Natural gas is used to heat the acid gas furnace to operating temperatures before H_2S is supplied to begin sulfur recovery processing. In normal operation the acid gas furnace is not a VOC source because the acid gas stream does not contain carbon compounds.

The TGTU thermal oxidizer always operates with a natural gas fuel supply.

Step 1: Identify Potential Control Technologies

VOC emissions from natural gas combustion are the result of incomplete fuel combustion. VOC emissions can be controlled with the following control technologies:

Post-combustion Controls:

(1) Thermal Oxidation
(2) Catalytic Oxidation
(3) Flares

Combustion controls:

(4) Good Combustion Practices

Post-combustion controls
Post-combustion controls identified for natural gas combustion units all include systems that supply energy to destroy pollutants through addition of more fuel.

Good Combustion Practices
Good combustion practices are a form of preventive controls that may have only a small effect on pollutant formation except in combination with other controls. Some principles of good combustion practice are taken as incorporated at the equipment design stage, such as proper design of burners and firebox components and ensuring adequate residence time. Other principles, such as minimizing air infiltration and maintaining equipment in accordance with a manufacturer's specification, may be taken as incorporated into the preventive maintenance plan for a unit. The element of good combustion practices that may have the most direct effect, and that may be considered as a control technology, is the control of the fuel-to-air combustion ratio, which can be achieved manually through tuneups as required by the NESHAP, 40 CFR 63, Subpart DDDDD or through control equipment such as an oxygen trim system.

Step 2: Eliminate Technically Infeasible Options

A search of the USEPA's RACT/BACT/LAER Clearinghouse indicates the use of good combustion practice for gas-fired combustion units is the most-commonly cited control for VOC emissions. Natural gas combustion is already efficient. It is possible to achieve VOC reductions from an add-on control device; however, any add-on oxidation control technology would not be cost effective since the VOC concentration in these units is relatively low and supplemental fuel cost would be prohibitive.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

Review of similar sources found in the RBLC database does not identify any cases where good combustion practices were incorporated into a determination of BACT for VOC. The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - VOC

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners*	*0.0054 lb/MMBtu 0.28 lb/hr, each*	*111 (max, ea) 159 (comb, bottle-necked)*
The source has proposed limiting VOC to 0.0054 lb/MMBtu, which is more restrictive than other sources found in the RBLC. Therefore this has been determined to be BACT for the proposed source.					
Sunoco	OH-0308 04-01447 (2/23/2009)	Sulfur Recovery Unit (new)	Tail gas treatment units and SRU incinerator thermal oxidizer low-nox burners	0.89 lb/hr 3.89 tpy (12-month rolling avg.) (equivalent to 0.052 lb/MMBtu) 60 ppmvd @ 0% O2	17 MMBtu/hr
BP Products, North America	OH-0357 P0111667 (9/20/2013)	Claus SRU	None	6.2 tpy each (equivalent to 0.04 lb/MMBtu)	120 (32.15 MMBtu/hr)
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Sulfur recovery process units	thermal oxidizer low NOx burners	0.2 lb/hr (0.85 tpy) (AP-42)	23.5 ton/hr
Note: Source was not constructed and it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Conoco Phillips	IL-0103 06050052 (8/5/2008)	Sulfur Recovery Units E and F	Good combustion practices for thermal oxidizers on tail gas treating unit	VOC: 0.005 lb/MMBtu (3-hr avg.)	
This RBLC entry is identified as LAER, therefore it is not considered as establishing BACT for the proposed source.					

Notes:
1. tpy - tons per twelve (12) consecutive months

Step 5: Select BACT

IDEM, OAQ has established VOC BACT for TGTUA and TGTUB as:

(a) VOC emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0054 lb/MMBtu and 0.28 lb/hr, each.

CO

In normal operations, the heat demand of the sulfur recovery process is supplied by combustion of hydrogen sulfide in the acid gas furnace. Natural gas is used to heat the acid gas furnace to operating temperatures before H_2S is supplied to begin sulfur recovery processing. In normal operation the acid gas furnace is not a CO source because the acid gas stream does not contain carbon compounds.

The TGTU thermal oxidizer always operates with a natural gas fuel supply.

Step 1: Identify Potential Control Technologies

Emissions of carbon monoxide (CO) are generally controlled by oxidation. CO control technologies include:

Post-combustion controls:

(1) Regenerative thermal oxidation;

(2) Catalytic oxidation;
(3) Flares

Combustion controls:

(4) Good Combustion Practices

Post-combustion controls
Post-combustion controls identified for natural gas combustion units all include systems that supply energy and oxygen to complete the combustion of CO to CO_2.

Good Combustion Practices
Good combustion practices are a form of preventive controls that may have only a small effect on pollutant formation except in combination with other controls. Some principles of good combustion practice are taken as incorporated at the equipment design stage, such as proper design of burners and firebox components and ensuring adequate residence time. Other principles, such as minimizing air infiltration and maintaining equipment in accordance with a manufacturer's specification, may be taken as incorporated into the preventive maintenance plan for a unit. The element of good combustion practices that may have the most direct effect, and that may be considered as a control technology, is the control of the fuel-to-air combustion ratio, which can be achieved manually through tuneups as required by the NESHAP, 40 CFR 63, Subpart DDDDD or through control equipment such as an oxygen trim system.

Step 2: Eliminate Technically Infeasible Options

Carbon monoxide emissions from boilers and heaters are the result of incomplete fuel combustion. While post-combustion control of CO emissions from an external combustion process may be possible in a physical sense, no demonstrated application of post-combustion control can be found. The EPA Air Pollution Control Cost Manual, 6th ed., (EPA/452/B-02-001, January 2002) has no information about controls for CO. Earlier references, such as Control Techniques for Carbon Monoxide Emissions (EPA-450/3-79-006, June 1979) offer no information about CO controls other than good combustion practices.

One very early reference, Control Techniques for Carbon Monoxide Emissions from Stationary Sources (AP-65, March 1970), notes that "The sources of CO in a petroleum refinery include: catalyst regeneration, coking operations, blanketing gas generators, flares, boilers, and process heaters. Only moving-bed catalyst regenerators and fluid cokers emit significant amounts of CO." The only control AP-65 suggests for CO in these processes, which are not found at Riverview Energy Corporation, are waste heat CO boilers that required a coke-burning rate of 18,000 pounds per hour for a reasonable payout.

In the absence of demonstrated success, post-combustion controls for CO such as RTO's, catalytic oxidation, and flares are considered technically infeasible. A search of the USEPA's RACT/BACT/LAER Clearinghouse indicates the use of good combustion practice and engineering design for gas-fired combustion units is the best control for CO emissions.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary. Good combustion practices are a feasible option.

Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - CO

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners, Good Combustion Practices*	*0.082 lb/MMBtu 4.33 lb/hr, each 65 ppmvd @ 0% O2 (30-day rolling avg.) CO CEMS*	*111 (max, ea) 159 (comb, bottle-necked)*
BP Products, North America	OH-0357 P0111667 (9/20/2013)	Claus SRU	None	2.7 lb/hr each 8.07 tpy 84 lb/MMscf (equivalent to 0.082 lb/MMBtu)	120 (32.15 MMBtu/hr)
Chevron Products	MS-0089 1280-00058 (4/14/2009)	Tail Gas Treating Units for SRU IV, V, and VI	Two low-NOx thermal oxidizers	22.75 lb/hr (3-hr rolling avg.), 99.7 tpy (12-month rolling avg.) 65 ppmvd @ 0% O2 (30-day rolling avg.) CO CEMS	1,220
Conoco Phillips	IL-0103 06050052 (8/5/2008)	Sulfur Recovery Units E and F	Good combustion practices for thermal oxidizers on tail gas treating unit	0.082 lb/MMBtu	
These are the most stringent limits for CO. Therefore, these have been determined to be BACT. Language regarding good combustion practices in the referenced permit for Conoco Phillips cannot be verified, but is accepted as establishing BACT for that source.					
Chevron Products	MS-0089 1280-00058 (4/14/2009)	Sulfur Recovery Units II and III	Two low-NOx thermal oxidizers	16.92 lb/hr (3-hr rolling avg.) 49.42 tpy (12-month rolling avg.) 100 ppmvd @ 0% O2 (30-day rolling avg.) CO CEMS	290
Sunoco	OH-0308 04-01447 (2/23/2009)	Sulfur Recovery Unit (new)	Tail gas treatment units and SRU incinerator thermal oxidizer low-nox burners	2.59 lb/hr 11.34 tpy (12-month rolling avg.) 0.15 lb/MMBtu incinerator	17 MMBtu/hr
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Sulfur recovery process units	thermal oxidizer low NOx burners	52.5 lb/hr (incineration of tail gas, each unit) 0.32 tpy 3 startup/shutdown events per year for each unit	23.5 ton/hr
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Texstar	TX-0501 6051, PSD-TX-55M3 (7/11/2006)	Tail gas incinerator stack	-	3.69 lb/hr 15.9 tpy	
The source is a natural gas liquids facility in SIC code 132 (*sic*) (also provides NAICS code of 221210), therefore this entry should not be considered as establishing BACT for the proposed source.					

Notes:

1. *tpy - tons per twelve (12) consecutive months*
2. *Good combustion practices shall include installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, and periodic tuneups that are required for units subject to 40 CFR 63, Subpart DDDDD.*

Step 5: Select BACT

IDEM, OAQ has established CO BACT for TGTUA and TGTUB as:

(a) CO emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 65 ppmv @ 0% O_2, shall not exceed 0.082 lb/MMBtu and 4.33 lb/hr, each.

(b) Incinerators (A-605A and A-605B) shall use good combustion practices. Good combustion practices shall include installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, on each fuel gas combustion unit.

GHGs

Step 1: Identify Potential Control Technologies

(1) Energy efficiency measures
(2) Post-combustion CO_2 capture and sequestration (CCS).

Step 2: Eliminate Technically Infeasible Options

Energy efficiency measures

An opportunity for reducing GHG emissions is to increase the energy efficiency. Because CO_2 emissions are a direct result of the amount of fuel fired (for a given fuel), the more efficient the process, the less fuel that is required and the less greenhouse gas emissions that result. Energy efficiency measures that can be applied include the following:

Some energy efficiency measures are built into combustion units, to the greatest possible extent, at the design stage. These are taken to include specification of refractories and insulating materials, and details of burners, combustion chambers, and heat exchangers. Design for the highest practical energy efficiency may be taken as a universal element of combustion systems because, if for no other reason, of the owner's interest in achieving the maximum energy recovery from the value of the fuel.

Systems to monitor and track performance of critical equipment and processes can help optimize operation. Using this information, research on machinery and equipment can be conducted, as could energy efficiency studies and other measures such as predictive maintenance. Scheduled preventive maintenance and rotation of redundant equipment helps minimize equipment downtime and optimize operation. Training programs appropriate to the functions of operating and maintenance personnel and good housekeeping programs as an element of preventive maintenance planning help decrease energy consumption.

Combustion equipment tune ups that may be required by applicable regulations, such as 40 CFR 63, Subpart DDDDD, contribute to achieving and maintaining the greatest possible level of energy efficiency. Such a requirement for tune ups, if applicable to a fuel gas combustion unit, is incorporated in permit conditions implementing the underlying regulation. Details of tune up requirements may not be included in permit BACT conditions if the requirements are easily found in other sections of a permit.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of energy efficiency is a technically feasible option for the heaters and boiler at this source.

Post-combustion CO_2 capture and sequestration (CCS)

Post-combustion CO_2 capture is a relatively new concept. In EPA's recent GHG BACT guidance, EPA takes the position that, "for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams". However, the heaters and boiler at Riverview do not fit into either of these categories. The EPA guidance document provides little specific guidance on whether or how to consider CCS in situations outside of the above quoted examples. However, some guidance specific to medium-sized natural gas boilers appears in its guidance document which presents an example GHG BACT analysis for a 250 MMBtu/hr natural gas fired boiler. In this EPA boiler example, carbon capture isn't listed or considered in the BACT analysis as a potentially available option.

Natural gas combustion heater exhaust streams have relatively low CO_2 concentrations (6-9% versus 12-15% for coal-boilers and >30% for high concentration industrial gas streams). This means that for a natural gas heater, a very large volume of gas needs to be treated to recover the CO_2. Additionally, the low concentration and low pressure complicate the absorption and desorption of the CO_2, which increases the energy required. Also, a low pressure absorption system creates a low pressure CO_2 stream which requires a very high energy demand for compression prior to transport. All these factors make the application of CO_2 capture on any natural gas combustion exhaust extremely difficult and expensive. Additionally, the cost of capturing CO_2 for smaller sources is more expensive due to the lack of economy-of-scale.

The CO_2 must be reused or liquefied, transported and stored. Pipelines are the most common. The CO_2 must be compressed to high pressures, which requires considerable energy consumption. At this time, existing infrastructure to support the transportation of CO_2 does not exist. Therefore, transportation of the CO_2 stream would require the construction of a pipeline to the nearest sequestration site.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of post-combustion CO_2 capture is not a technically or economically feasible option for the operations at this source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):
Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - CO_2e

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners, energy efficiency*	*40,872 tpy (combined)*	*111 (max, ea) 159 (comb, bottle-necked)*
BACT proposed by the source. Tons per year limits at other sources are not considered applicable because unit capacities are not available for comparison.					
Dakota Prairie Refining	ND-0031 PTC12090 (2/21/2013)	Sulfur recovery unit	none	1137 tpy	

Notes:
1. *tpy - tons per twelve (12) consecutive months*

2. *Energy efficiency is demonstrated by the application of good combustion practices including installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, and periodic tuneups that are required for units subject to 40 CFR 63, Subpart DDDDD.*

Step 5: Select BACT

IDEM, OAQ has established GHG BACT for TGTUA and TGTUB as:

(a) Carbon dioxide equivalent (CO_2e) emissions, as defined at 40 CFR 98.6, from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 40,872 tons per twelve (12) consecutive month period, combined, with compliance determined at the end of each month.

(b) Incinerators (A-605A and A-605B) shall use good combustion practices. Good combustion practices shall include installation and operation of an oxygen trim system, as defined at 40 CFR 63.7575, on each fuel gas combustion unit.

Sulfuric acid (H_2SO_4) mist

Step 1: Identify Potential Control Technologies

Wet scrubbers using water or caustic solutions are a possible control technology for acid mists.

Step 2: Eliminate Technically Infeasible Options

The tail gas treatment unit returns acid gas to the acid gas furnace upstream of the Claus reactors to recover sulfur to the highest practical degree. Because of the extremely low concentration of sulfuric acid mist in the TGTU thermal oxidizer exhaust and the high temperature of the gas stream, the overall mass transfer driving force is considered too low for practical application.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Sulfur Recovery/Tail Gas Treatment Unit (TGTU) - H_2SO_4 mist

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (Long tons/day)
Riverview Energy	*Proposed*	*Claus SRU TGTU (EU-3001 and EU-3002)*	*SRU Tail gas unit with incinerator burner and low-NOx burners*	*H_2SO_4: 0.0244 lb/MMBtu and 1.29 lb/hr, each (equivalent to 0.28 lb/long ton S)*	111 (max, ea) 159 (comb, bottle-necked)
Limits proposed by the source for sulfuric acid mist are more restrictive than any found in RBLC, therefore these are selected as BACT.					
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Sulfur recovery process units	thermal oxidizer low NOx burners	H_2SO_4: 2.37 lb/hr (10.4 tpy) (equivalent to 0.10 lb/long ton)	23.5 ton/hr
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					

Step 5: Select BACT

IDEM, OAQ has established sulfuric acid mist BACT for TGTUA and TGTUB as:

(a) Sulfuric Acid Mist (H_2SO_4 mist) emissions from the tail gas treatment unit stacks (TGTUA and TGTUB) shall not exceed 0.0244 lb/MMBtu and 1.29 lb/hr, each.

BACT Analysis
Flares

Step 1: Identify Potential Control Technologies

The following control technologies have been identified to control emissions from the flare:

(1) Flare design and good combustion practices;
(2) Process flaring minimization practices; and
(3) Flare Gas Recovery.

Add-on controls typically have not been utilized on flares.

Step 2: Eliminate Technically Infeasible Options

Flare design and good combustion practices
Flare design, good combustion practices and monitoring are key elements in emissions performance of flares. The flare must be properly operated and maintained in order to achieve the anticipated emission rates guaranteed by the flare manufacturer.

The use of proper flare design and good combustion practices is a technically feasible control option.

Process flaring minimization practices
To the extent actions can be taken to minimize the volume of gas going to the flare, emissions of CO will be less. Flaring minimization practices are feasible and are evaluated in the analysis of BACT.

The use of process flaring minimization practices is a technically feasible control option.

Flare Gas Recovery
Flare gas recovery is not a feasible option. These flares do not operate constantly; only the pilot flame does. There would not be anything to recover except in the rare case of a process upset – which would preclude the use of any heat recovered.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Flare - $PM/PM_{10}/PM_{2.5}$

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Riverview Energy	*Proposed*	*Loading flare*	*Operate in accordance with 40 CFR 60.18 Implement a Flare Management Plan as required by 40 CFR 60, Subpart Ja*	*sweep & pilot operation: use gaseous fuel PM (filterable): 0.0019 lb/MMBtu SB: 1.62E-03 lb/hr LP: 0.014 lb/hr HP: 0.014 lb/hr loading: 4.22E-04 lb/hr PM10/PM2.5: 0.0074 lb/MMBtu SB: 6.32E-03 lb/hr LP: 0.053 lb/hr HP: 0.053 lb/hr loading: 1.64E-03 lb/hr Flare stream operations:* VE: 0% except for 5 min during 2 cons. hrs	*0.20*
		Sulfur block flare			*0.77*
		Low Pressure flare			*6.50*
		High pressure flare			*6.50*
Agrium U.S. Inc.	AK-0083 AQ0083CPT 06 (1/6/2015)	1.25 MMBtu/hr Ammonia Tank Flare, 0.4 MMBtu/hr Emergency Flare, and 1.25 MMBtu/hr Small Flare	Work Practice Requirements and Limited Use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events)	PM/PM10/PM2.5: 0.0074 lb/MMBtu	
0.0074 lb/MMBtu is most stringent for PM10/PM2.5. Therefore this is determined to be BACT					
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Startup/Shutdown Flares	None	0.0076 lb/MMBtu 0% VE (6-min avg.)	-
		Biomethanator Flare	None	PM/PM10: 0.0019 lb/MMBtu 0% VE (6-min avg.)	6.4
0.0019 lb/MMBtu is most stringent for PM (filterable). Therefore this is determined to be BACT					
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hydrogen Plant feed gas - flare	flare	Comply with 40 CFR 60.18 VE: 0% except for 5 min during 2 cons. hrs	2472
Exxonmobil	TX-0796 6860, PSDTX1464 (4/20/2016)	HP Flare	None	None	
Exxonmobil	TX-0795 83702, PSDTX843M 1, PSDTX860M 1 (4/18/2016)	Flares	None	None	
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Main flare and Alky flare	None	Meet requirements of 40 CFR 60.18 and API Recommended Practices 520 and 521	-
Liberty Landfill	IN-0246 T181-33869-00035 (10/22/2015)	Landfill gas Flare	Good Combustion Practices	17 lb/MMcf, CH4 (converted to 0.017 lb/MMBtu)	
Golden Pass Terminal	TX-0766 116055, PSDTX1386, GHGPSDTX	Flares	None	None	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
	100 (9/11/2015)				
Citgo Refining and Chemicals	TX-0478 PSD-TX-408M3 (4/20/2015)	Acid gas flare	None	None	-
BASF	TX-0728 118239, N200 (4/1/2015)	Flares	None	None	
Corpus Christi Liquefaction	TX-0679 GHGPSDTX 123 (2/27/2015)	Flares	None	None	
ExxonMobil Corporation	AK-0082 AQ1201CPT 03 (1/23/2015)	50 MMscf/yr Drilling Flare, 35 MMscf/yr HP Flare-Pilot/Purge, 20 MMscf/yr LP Flare-Pilot/Purge	None	0.0264 lb/MMBtu	-
Norco Hydrogen	LA-0264 PSD-LA-750(M1) (9/4/2012)	Natural gas flare	Maintain minimum heat content of the flare gas at 200 btu/scf to ensure the flame at the flare tips at all the times.	0.01 lb/hr	0.31
Indiana Gasification	IN-0166 T147-30464-00060 (6/27/2012)	Syngas hydrocarbon flare	Flare minimization plan	PM/PM10: 3.21 lb/hr PM2.5: 3.01 lb/hr	0.27
		Acid Gas flare		None	0.27
This source was never constructed and the permit was revoked. Therefore the reference is not considered in determining BACT.					
Sabina Petrochemicals	TX-0575 41945, N018M1 (8/20/2010)	High and low pressure flares	None	None	1600 tpy
Lake Charles Cogeneration, LLC	LA-0231 PSD-LA-742 (6/22/2009)	acid gas flare	Good design and monitoring to ensure the presence of a flame at the flare tip at all the time	PM10: 0.01 lb/hr max	0.27 MMBtu/hr
This source is in SIC code 2865, therefore this entry is not considered as establishing BACT for the proposed source, which is in SIC code 2911					
Navajo Refining Co.	NM-0050 PSD-NM-195-M25 (12/14/2007)	Natural gas and hydrogen flare	None	None	7.5
Rohm and Haas Texas Inc.	TX-0487 PSD-TX-828M1 (3/24/2005)	Feed and exit gas flare	None	None	-

Flare - SO_2

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Riverview Energy	*Proposed*	*Loading flare*	*Operate in accordance with 40 CFR 60.18. Implement a Flare*	*Burn only natural gas or process off-gas in sweep or pilot mode.*	*0.20*
		Sulfur block flare			*0.77*
		Low Pressure flare			*6.50*

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
		High pressure flare	*Management Plan as required by 40 CFR 60, Subpart Ja*	*Limits during sweep or pilot operation:* *HP: 0.013 lb/hr* *LP: 0.013 lb/hr* *SB: 0.069 lb/hr* *Loading: 0.069*	*6.50*
Requirements of 40 CFR 60 103a(h) are considered BACT for sweep & pilot operations burning refinery fuel gas.					
Exxonmobil	TX-0796 6860, PSDTX1464 (4/20/2016)	HP Flare	None	None	
Exxonmobil	TX-0795 83702, PSDTX843M 1, PSDTX860M 1 (4/18/2016)	Flares	None	None	
CHS McPherson Refinery Inc	KS-0032 C-13055 (12/12/2015)	Main flare and Alky flare	None	Meet requirements of 40 CFR 60.18 and API Recommended Practices 520 and 521	-
Liberty Landfill	IN-0246 T181-33869-00035 (10/22/2015)	Landfill gas Flare	None	None	
Golden Pass Terminal	TX-0766 116055, PSDTX1386, GHGPSDTX 100 (9/11/2015)	Flares	None	None	
Citgo Refining and Chemicals	TX-0766 116055, PSDTX1386, GHGPSDTX 100 (9/11/2015)	Acid gas flare	None	None	-
BASF	TX-0478 PSD-TX-408M3 (4/20/2015)	Flares	None	SO_2: 1.02 lb/hr	
Corpus Christi Liquefaction	TX-0728 118239, N200 (4/1/2015)	Flares	None	None	
ExxonMobil Corporation	AK-0082 AQ1201CPT 03 (1/23/2015)	50 MMscf/yr Drilling Flare, 35 MMscf/yr HP Flare-Pilot/Purge, 20 MMscf/yr LP Flare-Pilot/Purge	None	None	-
Agrium U.S. Inc.	AK-0083 AQ0083CPT 06 (1/6/2015)	1.25 MMBtu/hr Ammonia Tank Flare, 0.4 MMBtu/hr Emergency Flare, and 1.25 MMBtu/hr Small Flare	None	None	
Norco Hydrogen	LA-0264 PSD-LA-750(M1) (9/4/2012)	Natural gas flare	None	None	0.31

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Indiana Gasification - IN	IN-0166 / T147-30464-00060 (6/27/2012)	Syngas hydrocarbon flare	None	Flare minimization plan	0.27
		Acid Gas flare	None		0.27
This source was never constructed and the permit was revoked. Therefore the reference is not considered in determining BACT.					
Sabina Petrochemicals	TX-0575 41945, N018M1 (8/20/2010)	High and low pressure flares	None	None	1600 tpy
Lake Charles Cogeneration, LLC	LA-0231 PSD-LA-742 (6/22/2009)	acid gas flare	no additional control	SO_2: 0.01 lb/hr max	0.27
Navajo Refining Co.	NM-0050 PSD-NM-195-M25 (12/14/2007)	Natural gas and hydrogen flare	None	SO_2: 0.1 lb/hr 0.4 tpy	7.5
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Startup/Shutdown Flares	None	SO_2: 0.395 lb/MMBtu	-
		Biomethanator Flare	None	SO_2: 0.0007 lb/MMBtu	6.4
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hydrogen Plant feed gas - flare	flare	Comply with 40 CFR 60.18 SO_2: 0.01 lb/hr	2472
Rohm and Haas Texas Inc.	TX-0487 PSD-TX-828M1 (3/24/2005)	Feed and exit gas flare	None	SO_2: 0.11 lb/hr 0.01 tpy	-

Flare - NOx

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Riverview Energy	*Proposed*	*Loading flare*	*Operate in accordance with 40 CFR 60.18. Implement a Flare Management Plan as required by 40 CFR 60, Subpart Ja*	*sweep & pilot operation: use gaseous fuel NOx: 0.099 lb/MMBtu SB: 8.46E-02 lb/hr LP: 0.71 lb/hr HP: 0.71 lb/hr loading: 2.20E-02 lb/hr Flare stream operations: NOx: 0.068 lb/MMBtu*	*0.20*
		Sulfur block flare			*0.77/0.85 (LHV/HHV)*
		Low Pressure flare			*6.50/7.22*
		High pressure flare			*6.50/7.22*
Liberty Landfill	IN-0246 T181-33869-00035 (10/22/2015)	Landfill gas Flare	Good Combustion Practices	NOx: 0.068 lb/MMBtu	
ExxonMobil Corporation	AK-0082 AQ1201CPT 03 (1/23/2015)	50 MMscf/yr Drilling Flare, 35 MMscf/yr HP Flare-Pilot/Purge, 20 MMscf/yr LP Flare-Pilot/Purge	None	NOx: 0.068 lb/MMBtu	-
Agrium U.S. Inc.	AK-0083 AQ0083CPT 06 (1/6/2015)	1.25 MMBtu/hr Ammonia Tank Flare, 0.4 MMBtu/hr Emergency Flare, and 1.25 MMBtu/hr Small Flare	Work Practice Requirements and Limited Use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events)	NOx: 0.068 lb/MMBtu	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
0.068 lb NOx/MMBtu, considered as while actively flaring because that is how the emission factor is defined in AP-42, Chapter 13.5 is most stringent for NOx. Therefore this is BACT					
Exxonmobil	TX-0796 6860, PSDTX1464 (4/20/2016)	HP Flare	None	None	
Exxonmobil	TX-0795 83702, PSDTX843M 1, PSDTX860M 1 (4/18/2016)	Flares	None	None	
Golden Pass Terminal	TX-0766 116055, PSDTX1386, GHGPSDTX 100 (9/11/2015)	Flares	None	None	
Citgo Refining and Chemicals	TX-0478 PSD-TX-408M3 (4/20/2015)	Acid gas flare	None	None	-
BASF	TX-0728 118239, N200 (4/1/2015)	Flares	None	NOx: 223.41 lb/hr (5.39 tpy)	
Corpus Christi Liquefaction	TX-0679 GHGPSDTX 123 (2/27/2015)	Flares	None	None	
Norco Hydrogen	LA-0264 PSD-LA-750(M1) (9/4/2012)	Natural gas flare	Proper Equipment designs and good combustion practices	NOx: 0.03 lb/hr (0.09 ton/yr) (calculated 0.097 lb/MMBtu)	0.31
Indiana Gasification - IN	IN-0166 T147-30464-00060 (6/27/2012)	Syngas hydrocarbon flare	Flare minimization plan	NOx: 43.09 lb/hr (calculated 160 lb/MMBtu)	0.27
Sabina Petrochemicals	TX-0575 41945, N018M1 (8/20/2010)	High and low pressure flares	None	9.07 tpy	1600 tpy
Lake Charles Cogeneration, LLC	LA-0231 PSD-LA-742 (6/22/2009)	acid gas flare	no additional control	NOx: 0.05 lb/hr max	0.27 MMBtu/hr
Navajo Refining Co.	NM-0050 PSD-NM-195-M25 (12/14/2007)	Natural gas and hydrogen flare	None	NOx: 0.54 lb/hr 2.38 tpy (calculated 0.072 lb/MMBtu)	7.5
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Startup/Shutdown Flares	None	NOx: 0.2 lb/MMBtu	-
		Biomethanator Flare	None	NOx: 0.07 lb/MMBtu	6.4
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hydrogen Plant feed gas - flare	flare	Comply with 40 CFR 60.18 NOx: 1.8 lb/hr	2472
Rohm and Haas Texas Inc.	TX-0487 PSD-TX-828M1 (3/24/2005)	Feed and exit gas flare	None	NOx: 130.65 lb/hr 7.78 tpy (0.0641 lb NOx/MMBtu)	-

Flare - VOC

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Riverview Energy	*Proposed*	*Loading flare (controlling the Naphtha loading operation and diesel loading operation)*	*Operate in accordance with 40 CFR 60.18. Implement a Flare Management Plan as required by 40 CFR 60, Subpart Ja*	*sweep & pilot operation: use gaseous fuel VOC: 0.0054 lb/MMBtu 1.20E-03 lb/hr Flare stream operations: 98% DRE Submerged loading when loading naphtha: 0.0082 lb/kgal when loading diesel: 0.014 lb/kgal*	*0.20*
		Sulfur block flare		*sweep & pilot operation: use gaseous fuel VOC: 0.0054 lb/MMBtu SB: 4.62E-03 lb/hr LP: 0.039 lb/hr HP: 0.039 lb/hr Flare stream operations: 98% DRE*	*0.77*
		Hydrogen plant flare			*6.50*
		High pressure flare			*6.50*
Agrium U.S. Inc.	AK-0083 AQ0083CPT 06 (1/6/2015)	1.25 MMBtu/hr Ammonia Tank Flare, 0.4 MMBtu/hr Emergency Flare, and 1.25 MMBtu/hr Small Flare	Work Practice Requirements and Limited Use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events)	0.0054 lb/MMBtu	
Midwest Fertilizer	IN-0173 T129-33576-00059 (6/4/2014)	Flare	NG pilot, flare minimization practices	0.0054 lb/MMBtu 47.26 lb/hr	
0.0054 lb/MMbtu is most stringent for VOC under pilot operating conditions. Therefore this is BACT.					
M&G Resins	TX-0671 108446, PSDTX1352 (12/1/2014)	Flare	None	40 CFR 60.18 0.01 lb/hr 99% DRE for compounds up to 3 carbons, 98% others	
Lone Star NGL Fractionators	TX-0723 N182 (11/21/2014)	Flare	Meet 60.18 for continuous flame or pilot monitoring, smokeless design, sufficient heat content in the waste gas, and limited tip velocity.	98% CE	
Dow Chemical	TX-0697 107153, PSDTX1328 (3/27/2014)	LP Flare	flare will meet NSPS 60.18 standards for continuous pilot flame, waste gas heat content and tip velocity	99% DRE for compounds up to C3 carbons, 98% others	
Dow Chemical	TX-0721 100787, PSDTX1314 (1/7/2013)	Flare	good combustion	5.5 lb/MMscf 99% DRE for compounds up to C3 carbons, 98% others	
Sabina Petrochemicals	TX-0575 41945, N018M1 (8/20/2010)	High and low pressure flares	None	0.32 tpy 98% CE	1600 tpy

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Biomethanator Flare	None	0.052 lb/MMBtu 98% CE	6.4
Exxonmobil	TX-0796 6860, PSDTX1464 (4/20/2016)	HP Flare	None	None	
Exxonmobil	TX-0795 83702, PSDTX843M 1, PSDTX860M 1 (4/18/2016)	Flares	None	None	
Liberty Landfill	IN-0246 T181-33869-00035 (10/22/2015)	Landfill gas Flare	None	None	
Golden Pass Terminal	TX-0766 116055, PSDTX1386, GHGPSDTX 100 (9/11/2015)	Flares	None	None	
BASF	TX-0728 118239, N200 (4/1/2015)	Flares	None	9.32 lb/hr	
Corpus Christi Liquefaction	TX-0679 GHGPSDTX 123 (2/27/2015)	Flares	None	None	
ExxonMobil Corporation	AK-0082 AQ1201CPT 03 (1/23/2015)	50 MMscf/yr Drilling Flare, 35 MMscf/yr HP Flare-Pilot/Purge, 20 MMscf/yr LP Flare-Pilot/Purge	None	0.14 lb/MMBtu	-
Anadarko Petroleum	FL-0347 OCS-EPA-R4015 (9/16/2014)	Boom Flare	Good combustion practices and proper flare maintenance	None	
Norco Hydrogen	LA-0264 PSD-LA-750(M1) (9/4/2012)	Natural gas flare	None	None	0.31
Indiana Gasification - IN	IN-0166 T147-30464-00060 (6/27/2012)	Syngas hydrocarbon flare	None	None	0.27
		Acid Gas flare	None	Flare minimization plan	0.27
This source was never constructed and the permit was revoked. Therefore the reference is not considered in determining BACT.					
WTG Benedum	TX-0605 8941, PSDTX487M 1 (12/21/2011)	Acid gas flare	None	None	-
Navajo Refining Co.	NM-0050 PSD-NM-195-M25 (12/14/2007)	Natural gas and hydrogen flare	None	0.03 lb/hr 0.14 tpy (calculated 0.004 lb/MMBtu)	7.5

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Startup/Shutdown Flares	None	0.006 lb/MMBtu	-
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hydrogen Plant feed gas - flare	flare	Comply with 40 CFR 60.18 VOC: 0.01 lb/hr	2472
Rohm and Haas Texas Inc.	TX-0487 PSD-TX-828M1 (3/24/2005)	Feed and exit gas flare	None	0.22 lb/hr 0.09 tpy	-

IDEM is aware that that the above control technologies may be able to periodically achieve control efficiencies that exceed 98% under certain operating conditions. However, BACT must be achievable on a consistent basis under normal operational conditions. BACT limitations do not necessarily reflect the highest possible control efficiency achievable by the technology on which the emission limitation is based. The permitting authority has the discretion to base the emission limitation on a control efficiency that is somewhat lower than the optimal level. There are several reasons why the permitting authority might choose to do this. One reason is that the control efficiency achievable through the use of the technology may fluctuate, so that it would not always achieve its optimal control efficiency. In that case, setting the emission limitation to reflect the highest control efficiency would make violations of the permit unavoidable. To account for this possibility, a permitting authority must be allowed a certain degree of discretion to set the emission limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the Permittee to achieve compliance consistently. While we recognize that greater than 98% may be achievable as an average during testing, IDEM allows for sources to include a safety factor, or margin of error, to allow for minor variations in the operation of the emission units and the control device.

Therefore, the proposed VOC control of 98% is considered the top BACT for this operation.

<u>Flare - CO</u>

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Riverview Energy	*Proposed*	*Loading flare*	*Operate in accordance with 40 CFR 60.18*	*sweep & pilot operation: use gaseous fuel CO: 0.083 lb/MMBtu SB: 7.09E-02 lb/hr LP: 0.60 lb/hr HP: 0.60 lb/hr loading: 1.84E-02 lb/hr Flare stream operations: CO: 0.31 lb/MMBtu*	*0.20*
		Sulfur block flare			*0.77*
		Hydrogen plant flare			*6.50*
		High pressure flare			*6.50*
0.31 lb CO/MMBtu, considered as while actively flaring in conformance with 40 CFR 60.18 because that is how the emission factor is defined in AP-42, Chapter 13.5 is most stringent for CO. Therefore this is considered BACT for CO.					
Exxonmobil	TX-0796 6860, PSDTX1464 (4/20/2016)	HP Flare	NSPS §60.18	155.0 tpy	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Exxonmobil	TX-0795 83702, PSDTX843M 1, PSDTX860M 1 (4/18/2016)	Flares	NSPS §60.18	188.0 tpy	
Liberty Landfill	IN-0246 T181-33869-00035 (10/22/2015)	Landfill gas Flare	Good combustion practices	CO: 0.37 lb/MMBtu	
Ticona Polymers	TX-0774 123216, PSDTX1438, GHGPSDTX (11/12/2015)	Reformer	Flare (SSM)	CO: 50 ppmvd@ 3% O2 99% DRE	
Golden Pass Terminal	TX-0766 116055, PSDTX1386, GHGPSDTX 100 (9/11/2015)	Flares	None	None	
Citgo Refining and Chemicals	TX-0478 PSD-TX-408M3 (4/20/2015)	Acid gas flare	None	None	-
BASF	TX-0728 118239, N200 (4/1/2015)	Flares	None	CO: 950.41 lb/hr 98% CE	
Corpus Christi Liquefaction	TX-0679 GHGPSDTX 123 (2/27/2015)	Flares	None	None	
ExxonMobil Corporation	AK-0082 AQ1201CPT 03 (1/23/2015)	50 MMscf/yr Drilling Flare, 35 MMscf/yr HP Flare-Pilot/Purge, 20 MMscf/yr LP Flare-Pilot/Purge	None	CO: 0.37 lb/MMBtu	-
Agrium U.S. Inc.	AK-0083 AQ0083CPT 06 (1/6/2015)	1.25 MMBtu/hr Ammonia Tank Flare, 0.4 MMBtu/hr Emergency Flare, and 1.25 MMBtu/hr Small Flare	Work Practice Requirements and Limited Use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events)	CO: 0.37 lb/MMBtu	
M&G Resins	TX-0671 108446, PSDTX1352 (12/1/2014)	Flare	None	None	
Lone Star NGL Fractionators	TX-0723 N182 (11/21/2014)	Flare	NSPS §60.18	CO: 0.2755 lb/MMBtu	
This entry is not applied as BACT because the design and operating conditions are not described. Open flares, such as those proposed for Riverview Energy are not capable of being tested for emission. The AP-42 emission factor is based on operating in conformance with the requirements of 40 CFR 60.18.					
Anadarko Petroleum	FL-0347 OCS-EPA-R4015 (9/16/2014)	Boom Flare	Good combustion practices and proper flare maintenance	None	
Midwest Fertilizer	IN-0173 T129-33576-00059 (6/4/2014)	Flare	Flare minimization practices, NG pilot	CO: 0.37 lb/MMBtu 3240.16 lb/hr	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (MMBtu/hr)
Dow Chemical	TX-0697 107153, PSDTX1328 (3/27/2014)	LP Flare	Good combustion	CO: 0.3503 lb/MMBtu	
Dow Chemical	TX-0721 100787, PSDTX1314 (1/7/2013)	Flare	None	None	
Indiana Gasification - IN	IN-0166 T147-30464-00060 (6/27/2012)	Syngas hydrocarbon flare	Flare minimization plan	CO: 172.4 lb/hr (calculated 638 lb/MMBtu)	0.27
		Acid Gas flare	Flare minimization plan	None	0.27
This source was never constructed and the permit was revoked. Therefore the reference is not considered in determining BACT					
Sabina Petrochemicals	TX-0575 41945, N018M1 (8/20/2010)	High and low pressure flares	None	None	1600 tpy
Lake Charles Cogeneration, LLC	LA-0231 PSD-LA-742 (6/22/2009)	acid gas flare	Good design and monitoring to ensure the presence of a flame at the flare tip at all the time	CO: 0.01 lb/hr max	0.27 MMBtu/hr
Navajo Refining Co.	NM-0050 PSD-NM-195-M25 (12/14/2007)	Natural gas and hydrogen flare	None	CO: 0.2 lb/hr 0.8 tpy (calculated 0.027 lb/MMBtu)	7.5
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Startup/Shutdown Flares	None	CO: 1.1 lb/MMBtu	-
		Biomethanator Flare	None	CO: 0.37 lb/MMBtu	6.4
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hydrogen Plant feed gas - flare	flare	Comply with 40 CFR 60.18 CO: 20.22 lb/hr	2472
Rohm and Haas Texas Inc.	TX-0487 PSD-TX-828M1 (3/24/2005)	Feed and exit gas flare	None	CO: 699.09 lb/hr 136.39 tpy (0.5496 lb CO/MMBtu)	-

Flare - CO_2e

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Loading flare*	*Operate in accordance with 40 CFR 60.18 and other applicable NSPS and NESHAP*	*559 tpy*	*0.20*
		Sulfur block flare		*448 tpy*	*0.77*
		LP flare		*3,781 tpy*	*6.50*
		High pressure flare		*3,781 tpy*	*6.50*
BACT determined for site-specific conditions because rating and gas composition applied to other sources is not considered transferable to Riverview Energy.					
Citgo Refining and Chemicals	TX-0478 PSD-TX-408M3 (4/20/2015)	Acid gas flare	None	None	-
Exxonmobil	TX-0796 6860, PSDTX1464 (4/20/2016)	HP Flare	None	None	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Exxonmobil	TX-0795 83702, PSDTX843M 1, PSDTX860M 1 (4/18/2016)	Flares	None	None	
ExxonMobil Corporation	AK-0082 AQ1201CPT 03 (1/23/2015)	50 MMscf/yr Drilling Flare, 35 MMscf/yr HP Flare-Pilot/Purge, 20 MMscf/yr LP Flare-Pilot/Purge	None	5317 tpy combined	-
Agrium U.S. Inc.	AK-0083 AQ0083CPT 06 (1/6/2015)	1.25 MMBtu/hr Ammonia Tank Flare, 0.4 MMBtu/hr Emergency Flare, and 1.25 MMBtu/hr Small Flare	Work Practice Requirements and Limited Use (limit venting to 168 hr/yr each during startup, shutdown, and maintenance events)	59.61 ton/MMscf 1500 tpy combined	
Liberty Landfill	IN-0246 T181-33869-00035 (10/22/2015)	Landfill gas Flare	None	None	
Golden Pass Terminal	TX-0766 116055, PSDTX1386, GHGPSDTX 100 (9/11/2015)	Flares	Equipment specifications & work practices- good combustion practices	NSPS §60.18	
BASF	TX-0728 118239, N200 (4/1/2015)	Flares	None	None	
Corpus Christi Liquefaction	TX-0679 GHGPSDTX 123 (2/27/2015)	Flares	Design to 40 CFR 60.18 to achieve 99% DRE for methane		
M&G Resins	TX-0671 108446, PSDTX1352 (12/1/2014)	Flare	None	None	
Anadarko Petroleum	FL-0347 OCS-EPA-R4015 (9/16/2014)	Boom Flare	None	None	
Cronus Chemicals	IL-0114 (9/5/2014)	Ammonia Plant Flare	None	25971 tpy	
Abengoa Bioenergy	IN-0186 T129-33077-00050 (6/18/2014)	Flare	Burn NG, flare minimization plan	None	
C3 Petrochemicals	TX-0744 PSD-TX-1342-GHG (6/12/2014)	Flare	install a continuous flow monitor and composition analyzer that provides a record of the vent stream flow and composition to the flare	178 tpy 98% DRE	
Midwest Fertilizer	IN-0173 T129-33576-00059 (6/4/2014)	Flare	NG pilot, flare minimization practices	116.89 lb/MMBtu 511.81 tph	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Lone Star NGL Fractionators	TX-0747 PSD-TX-110274-GHG (4/16/2014)	Flare	monitor the BTU content on the flared gas, and will have air assisted combustion allowing for improved flare gas combustion control and minimizing periods of poor combustion. Periodic maintenance will help maintain the efficiency of the flare.	52.0 tpy rolling	
Jet Corr	IN-0228 T127-33924-00094 (3/27/2014)	Biogas flare	Good engineering design and fuel efficient design	CO_2e: 3825 tpy	
Dow Chemical	TX-0697 107153, PSDTX1328 (3/27/2014)	LP Flare	None	None	
Dow Chemical	TX-0721 100787, PSDTX1314 (1/7/2013)	Flare	None	None	
Norco Hydrogen	LA-0264 PSD-LA-750(M1) (9/4/2012)	Nat gas flare	None	None	0.31
Indiana Gasification - IN	IN-0166 T147-30464-00060 (6/27/2012)	Syngas hydrocarbon flare	-	*see note	0.27
		Acid Gas flare		Flare minimization plan	0.27
This source was never constructed and the permit was revoked. Therefore the reference is not considered in determining BACT					
Sabina Petrochemicals	TX-0575 41945, N018M1 (8/20/2010)	High and low pressure flares	None	None	1600 tpy
Navajo Refining Co.	NM-0050 PSD-NM-195-M25 (12/14/2007)	Natural gas and hydrogen flare	None	None	7.5
Homeland Energy Solutions, LLC	IA-0089 07-A-955P to 07-A-982P (8/8/2007)	Startup/Shutdown Flares	None	None	-
		Biomethanator Flare	None	None	6.4
Rohm and Haas Texas Inc.	TX-0487 PSD-TX-828M1 (3/24/2005)	Feed and exit gas flare	None	None	-

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

(a) The units shall burn only natural gas and process off-gas as supplemental and pilot fuel.

(b) The Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the flares shall be as follows:

(1) Particulate matter emissions while operating in sweep and pilot mode shall not exceed:

Emission Limitations			
Unit ID	**Pollutant**	**lb/MMBtu**	**lb/hr**
HP Flare	PM (filterable)	0.0019	0.014
	PM_{10}	0.0074	0.053
	$PM_{2.5}$	0.0074	0.053
LP Flare	PM (filterable)	0.0019	0.014
	PM_{10}	0.0074	0.053
	$PM_{2.5}$	0.0074	0.053
SB Flare	PM (filterable)	0.0019	1.62E-03
	PM_{10}	0.0074	6.32E-03
	$PM_{2.5}$	0.0074	6.32E-03
Loading Flare	PM (filterable)	0.0019	4.22E-04
	PM10	0.0074	1.64E-03
	PM2.5	0.0074	1.64E-03

(2) The HP Flare and LP Flare shall operate with no visible emissions, except for periods not to exceed a total of five (5) minutes during any two (2) consecutive hours when flaring a process stream.

(c) The Best Available Control Technology (PSD BACT) for SO_2 for the flares shall be as follows:

(1) The Permittee shall burn only natural gas and process off-gas in any flare as supplemental or pilot fuel gas.

(2) SO_2 emissions while operating in sweep and pilot mode shall not exceed:

SO_2 Emission Limitations	
Unit ID	**lb/hr**
HP Flare	0.013
LP Flare	0.013

(3) SO_2 emissions from the SB Flare shall not exceed 0.069 lb/hr when operating in sweep and pilot mode.

(4) SO_2 emissions from the Loading Flare shall not exceed 0.069 lb/hr when operating in pilot mode.

(d) The Best Available Control Technology (PSD BACT) for NOx for the flares shall be as follows:

(1) NOx emissions while operating in sweep and pilot mode shall not exceed:

NOx Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
HP Flare	0.099	0.71
LP Flare	0.099	0.71
SB Flare	0.099	8.46E-02
Loading Flare	0.099	2.20E-02

(2) NOx emissions shall not exceed 0.068 lb/MMBtu (LHV) when flaring a process stream.

(e) The Best Available Control Technology (PSD BACT) for VOC for the flares shall be as follows:

(1) VOC emissions while operating in sweep and pilot mode shall not exceed:

VOC Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
HP Flare	0.0054	0.039
LP Flare	0.0054	0.039
SB Flare	0.0054	4.62E-03

(2) VOC destruction and removal efficiency shall not be less than 98% when flaring a process stream.

(3) VOC emissions while operating in pilot mode shall not exceed:

VOC Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
Loading Flare	0.0054	1.20E-03

(f) The Best Available Control Technology (PSD BACT) for CO for the flares shall be as follows:

(1) CO emissions while operating in purge and pilot mode shall not exceed:

CO Emission Limitations		
Unit ID	**lb/MMBtu**	**lb/hr**
HP Flare	0.083	0.60
LP Flare	0.083	0.60
SB Flare	0.083	7.09E-02
Loading Flare (pilot only)	0.083	1.84E-02

(2) CO emissions shall not exceed 0.31 lb/MMBtu (LHV) when flaring a process stream.

(g) Carbon dioxide equivalent (CO_2e) emissions, as defined at 40 CFR 98.6, from the flares listed in the table below when operating in purge and pilot mode shall not exceed the values shown per twelve (12) consecutive month period, with compliance determined at the end of each month.

Emission Limitations	
Unit ID	**CO_2e Limit**
Sulfur Block Flare	448
LP Flare	3,781
HP Flare	3,781
Loading Flare	559

VOC BACT Analysis
Tanks

Step 1: Identify Potential Control Technologies

Add-on controls:

There are two general categories of control methods for volatile organic compounds (VOCs): destruction methods and reclamation methods. Destruction control methods reduce the VOC concentration by high temperature oxidation into carbon dioxide and water vapor. Reclamation control methods consist of capturing VOCs for reuse or disposal. These are discussed in more detail below.

Destruction Control Methods
The destruction of organic compounds usually requires temperatures ranging from 1200°F to 2200°F for direct thermal oxidizers or 600°F to 1200°F for catalytic systems. Combustion temperature depends on the chemical composition and the desired destruction efficiency. Carbon dioxide and water vapor are the typical products of complete combustion. Turbulent mixing and combustion chamber retention times of 0.5 to 1.0 seconds are needed to obtain high destruction efficiencies.

Fume oxidizers typically need supplemental fuel. Concentrated VOC streams with high heat contents obviously require less supplementary fuel than more dilute streams. VOC streams sometimes have a heat content high enough to be self-sustaining, but a supplemental fuel-firing rate equal to about 5% of the total oxidizer heat input is usually needed to stabilize the burner flame. Natural gas is the most common fuel for VOC oxidizers, but fuel oil is an option in some circumstances.

Destruction control methods include:

(a) Thermal Oxidizer:

Thermal oxidation is the process of oxidizing VOC in a waste gas stream by raising the temperature above the VOC's auto-ignition point in the presence of oxygen for sufficient time to completely oxidize the organic contaminants to carbon dioxide and water. The residence time, temperature, flow velocity and mixing, and the oxygen concentration in the combustion chamber affect the oxidation rate and destruction efficiency. Thermal oxidizers operating costs are relatively high, since they typically require combustion of an auxiliary fuel (e.g., natural gas) to maintain combustion chamber temperature high enough to completely oxidize the contaminant gases. In general, thermal oxidizers are less efficient at treating waste gas streams with highly variable flowrates, since the variable flowrate results in varying residence times, combustion chamber temperature, and poor mixing. In addition, thermal oxidizers are also not generally cost-effective for low-concentration, high-flow organic vapor streams.

Thermal oxidizers can achieve 95-99.99+% VOC control efficiency and can be used over a wide range of organic vapor concentrations, but perform best at inlet concentrations of around 1,500-

3,000 ppmv. Thermal oxidizers are typically designed to have a residence time of 0.3 to 1.0 second and combustion chamber temperatures between 1,200 and 2,000°F. In order to meet 98% or greater control or a 20 parts per million by volume (ppmv) compound exit concentration of non-halogenated organics, thermal oxidizers should typically be operated at a residence time of at least 0.75 seconds, a combustion chamber temperature of at least 1600°F, and with proper mixing. While thermal oxidation provides efficient VOC control, other pollutants such as nitrogen oxides and carbon monoxide are formed from the combustion process.

Thermal oxidizers are not generally recommended for controlling gases containing halogen- or sulfur-containing compounds, because of the formation of hydrogen chloride, hydrogen fluoride gas, sulfur dioxide, and other highly corrosive acid gases. It may be necessary to install a post-oxidation acid gas treatment system in such cases, depending on the outlet concentration. This would likely make incineration an uneconomical option. For halogenated VOC streams, a combustion temperature of 2000°F, a residence time of 1.0 second, and use of an acid gas scrubber on the outlet is recommended.

The three types of thermal oxidation systems include direct flame, recuperative, and regenerative thermal oxidizers, which are differentiated by the type of heat recovery equipment used.

(1) Direct Flame Thermal Oxidizer

A direct flame thermal oxidizer is comprised of a combustion chamber and does not include any heat recovery of exhaust air by a heat exchanger.

(2) Recuperative Thermal Oxidizer

A recuperative thermal oxidizer is comprised of the combustion chamber, a heat exchanger for preheating the untreated VOC gas stream, and, if cost-effective, a secondary energy recovery heat exchanger. In a recuperative thermal oxidizer, the untreated VOC gas stream entering the oxidizer is preheated using the heat content of the treated gas stream exiting the oxidizer using a heat exchanger, resulting in improved oxidizer efficiency and reduced auxiliary fuel usage. Recuperative thermal oxidizers usually are more economical than direct flame thermal oxidizers because they typically recover 40 to 70% of the waste heat from the exhaust gases.

(3) Regenerative Thermal Oxidizer

A regenerative thermal oxidizer typically consists of a set of 2 or 3 packed ceramic beds that are used to recover heat from hot combustion gases that are generated during combustion of the VOC gas stream and auxiliary fuel, resulting in improved oxidizer efficiency and reduced auxiliary fuel usage. An "inlet" bed is used to pre-heat the untreated VOC gas stream, an "outlet" bed is used to recover heat from the treated gas stream, and one bed is in a purge cycle. The purge cycle is needed to prevent emission spikes each time the gas flow is redirected. The oxidizer is operated on a rotating schedule, where the gas flow through the ceramic beds is redirected periodically using a set of gas flow dampers. Once the heat energy of the "inlet" ceramic bed has been depleted, the flow through the system is redirected so that the untreated VOC gas stream entering the oxidizer is directed through the previously heated "outlet" ceramic bed. Regenerative thermal oxidizers have much higher heat recovery efficiencies than recuperative thermal oxidizers, recovering 85 to 95% of the heat from the treated gas stream, and therefore have lower auxiliary fuel requirements. However, compared to direct flame and recuperative thermal oxidizers, regenerative thermal oxidizers typically have higher capital (equipment and installation) costs, are larger and heavier, and have higher maintenance costs.

(b) Catalytic Oxidizer:

Catalytic oxidation is the process of oxidizing organic contaminants in a waste gas stream within a heated chamber containing a catalyst bed in the presence of oxygen for sufficient time to completely oxidize the organic contaminants to carbon dioxide and water. The catalyst is used to lower the activation energy of the oxidation reaction, enabling the oxidation to occur at lower reaction temperatures compared to thermal oxidizers. The residence time, temperature, flow velocity and mixing, the oxygen concentration, and type of catalyst used in the combustion chamber affect the oxidation rate and destruction efficiency. Catalytic oxidizers typically require combustion of an auxiliary fuel (e.g., natural gas) to maintain combustion chamber temperature high enough to completely oxidize the contaminant gases. Catalytic oxidizers operate at lower temperatures and require less fuel than thermal oxidizers, they have a smaller footprint, and they need little or no insulation. The catalyst bed is usually composed of the following: (1) the substrate, typically ceramic or metal honeycombs, grids, mesh pads, or beads; (2) the carrier, a high surface area inorganic material such as alumina that is bonded to the substrate that contains a complex pore structure; and (3) the catalyst, a thin layer of material deposited onto the carrier. The most widely used catalysts for VOC oxidation are noble metals, such as platinum, palladium and rhodium or mixtures thereof. Base metal catalysts, such as oxides of chromium, cobalt, copper, manganese, titanium, and vanadium may also be used for VOC oxidation. Similar to thermal oxidizers, catalytic oxidizers may use regenerative or recuperative heat recovery to reduce auxiliary fuel requirements, where the untreated VOC gas stream entering the catalytic oxidizer is preheated using the heat content of the treated gas stream exiting the catalytic oxidizer.

Catalytic oxidizers can achieve 90-99% VOC control efficiency, depending on the oxidizer design and waste stream characteristics. Catalytic oxidizers are typically designed to have a residence time of 0.5 seconds or less and combustion chamber temperatures between 600 and 1,200°F. Catalytic oxidation is most suited to waste gas streams with little variation in the flow rate and type and concentration of VOC to be treated. In addition, catalytic oxidizers should not be used for waste gas streams that have a high concentration of particles, silicone, sulfur, halogen compounds, and/or heavy hydrocarbons that can cause fouling or masking of the catalyst, and for waste gas streams that contain metals such as mercury, phosphorus, arsenic, antimony, bismuth, lead, zinc, and/or tin that can cause catalyst poisoning.

(c) Flare:

Flaring is the process of oxidizing VOC in a waste gas stream by piping the waste gas to a remote, usually elevated location and burning it in a flame using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing. Flares are generally categorized in two ways: (1) by the height of the flare tip (i.e., ground or elevated), and (2) by the method of enhancing mixing at the flare tip (i.e., steam-assisted, air-assisted, pressure-assisted, or non-assisted). Flares can be used to control almost any VOC stream, and can typically handle large fluctuations in VOC concentration, flow rate, heating value, and inert species content. Flaring is appropriate for continuous, batch, and variable flow vent stream applications, but the primary use is that of a safety device used to control a large volume of pollutant resulting from upset conditions. Flares have primarily been used in petroleum production, petroleum refineries, and chemical plants to control waste gas streams containing low molecular weight VOC with high heating values.

A properly operated flare can achieve 98+% VOC control efficiency when controlling emission streams with heat contents greater than 300 British thermal units per standard cubic foot (Btu/scf). If the waste gas stream has a heat content less than 300 Btu/scf, auxiliary fuel must be introduced in sufficient quantity to make up the difference. The VOC destruction efficiency of a flare depends upon the waste gas characteristics (density, flammability, heating value, and VOC component autoignition temperatures) and the combustion zone conditions (temperature, residence time, mixing, and available oxygen). While flares can provide efficient VOC control, other pollutants such as nitrogen oxides (NOx) and carbon monoxide (CO) are formed from the combustion process. Flares are not generally recommended for controlling gases containing halogen- or sulfur-containing compounds, because of the formation of hydrogen chloride, hydrogen fluoride gas, sulfur dioxide, and other highly corrosive acid gases.

Reclamation Control Methods
Organic compounds may be reclaimed by one of three possible methods: adsorption, absorption (scrubbing), or condensation. In general, the organic compounds are separated from the emission stream and reclaimed for reuse or disposal. Depending on the nature of the contaminant and the inlet concentration of the emission stream, recovery technologies can reach efficiencies of 98%.

(d) Carbon Adsorption Unit:

Carbon adsorption is a process where VOCs are removed from a waste gas stream when it is passed through a bed containing activated carbon particles, which have a highly porous structure with a large surface-to-volume ratio. Carbon adsorption systems usually operate in two phases: adsorption and desorption. During adsorption, the majority of the VOC molecules migrate from the gas stream to the surface of the activated carbon (through the activated carbon pores) where it is lightly held to the surface by weak intermolecular forces known as van der Waals' forces. As the activated carbon bed approaches saturation with VOC, its control efficiency drops, and the bed must be taken offline to be replaced or regenerated. Typically, two activated carbon beds are utilized on a rotating schedule, where a second bed (containing fresh or previously regenerated activated carbon) is brought online to continue controlling the VOC gas stream while the first bed is being replaced or regenerated. In regenerative systems, most VOC gases can be desorbed and removed from the activated carbon bed by heating the bed to a sufficiently high temperature, usually via steam or hot air, or by reducing the pressure within the bed to a sufficiently low value (vacuum desorption). The regenerated activated carbon can be reused and the VOCs that are removed from the bed can be reclaimed or destroyed.

Carbon adsorber size and purchase cost depend primarily on the gas stream volumetric flow rate, temperature, pressure, VOC composition, VOC mass loading, and moisture and particulate contents. The adsorptive capacity of an activated carbon bed for a VOC gas tends to increase with the VOC gas phase concentration, molecular weight, diffusivity, polarity, and boiling point. Carbon adsorption systems can be used for VOC gas concentrations from less than 10 ppm to approximately 10,000 ppm. Carbon adsorption systems (in general) are usually limited to waste gas streams with VOC compounds having a molecular weight of more than 50 and less than approximately 200 lb/lb-mole, since low molecular weight organics usually do not adsorb sufficiently and high molecular weight compounds are difficult to desorb and remove during the desorption cycle. Industrial applications of adsorption systems include control for dry cleaning, degreasing, paint spraying, solvent extraction, metal foil coating, paper coating, plastic film coating, printing, pharmaceuticals, rubber, linoleum, and transparent wrapping.

Carbon adsorption systems can achieve 95-99% VOC control efficiency. Carbon adsorption system control efficiency increases with reduced VOC gas stream temperatures. Therefore, high temperature VOC gas streams are typically cooled prior to entry into the activated carbon bed. Particulate matter and high moisture concentrations present in the gas stream compete with the VOC for pore space within the activated carbon and thereby reduce the VOC adsorptive capacity and control efficiency of the carbon adsorption systems. In addition, particulate matter and moisture can become entrained within the carbon bed, causing operating problems such as increased pressure drop across the bed.

(e) Gas Absorption (wet scrubber):

A wet scrubber is an absorption system in which a waste gas stream is interacted with a scrubbing fluid inside a contact chamber in order to strip particulate or gaseous pollutants from the waste gas stream through the processes of diffusion and dissolution. In many cases, an additive such as an acid, a base, or a VOC oxidizing agent is dissolved in the scrubbing fluid so that the dissolved gaseous pollutant chemically reacts with the scrubbing fluid to form a non-volatile or soluble product, thereby allowing additional gaseous pollutant to be absorbed by the scrubbing fluid. The four types of wet scrubber systems include packed towers, plate (or tray) columns, venturi scrubbers, and spray chambers. Gas and liquid flow through an absorber may be countercurrent, crosscurrent, or cocurrent. When used as an emission control technique, wet scrubbers are typically used for controlling particulate, acid gases, halogen gases, and highly soluble gases such as sulfur dioxide and ammonia.

If a wet scrubber is used for VOC control, the scrubbing fluid chosen should have a high solubility for the VOC gas, a low vapor pressure, a low viscosity, and should be relatively inexpensive. Water is the most commonly used scrubbing fluid for absorbing highly water-soluble (hydrophilic) VOC compounds such as methanol, ethanol, isopropanol, butanol, acetone, and formaldehyde. Other scrubbing fluid such as mineral oils, nonvolatile hydrocarbon oils, and aqueous solutions containing surfactants or amphiphilic block copolymers may be used for absorbing water-insoluble (hydrophobic) VOC compounds. Physical absorption is typically enhanced by lower temperatures, greater scrubbing fluid contacting time and surface area, higher scrubbing fluid to VOC ratio, and higher VOC concentrations in the gas stream.

Wet scrubber systems can achieve 70-99% VOC control efficiency, depending on the VOC solubility in the scrubbing fluid, the VOC-scrubbing fluid temperature, the scrubbing fluid contacting time and surface area, the scrubbing fluid to VOC ratio, the VOC concentration in the gas stream, and whether the scrubbing fluid contains a VOC oxidizing agent. Wet scrubber absorption system control efficiency increases with reduced VOC gas stream temperatures. Therefore, high temperature VOC gas streams are typically cooled prior to entry into the wet scrubber. When used to control VOC, the spent scrubbing fluid must be regenerated, treated, or shipped offsite for proper disposal.

(f) Condensation Unit:

Condensation is the separation of VOCs from an emission stream through a phase change, by either increasing the system pressure or, more commonly, lowering the system temperature below the dew point of the VOC vapor. Three types of condensers are used for air pollution Controls: (1) conventional non-refrigeration systems (such as cold-water direct contact condensers similar to wet scrubbers and cold-water indirect heat exchangers); (2) refrigeration systems (including mechanical compression refrigeration using chlorofluorocarbons (CFCs) and hydrofluorocarbons (HFCs) and Reverse Brayton Cycle refrigeration); and (3) cryogenic systems that utilize liquid nitrogen (including direct contact condensers and indirect heat exchangers).

Condensation units control VOC more efficiently when they are used for gas streams containing high concentrations of VOC and with low exhaust volumes. Condensation units are typically utilized at sources where there is a significant cost benefit to recovering the organic liquid for reuse, where the recovered organic liquids do not contain multiple organic compounds or water that require separation, and where the heat content of gas stream will not overload the refrigeration system. In addition, condensation units are typically used only on gas streams that have little or no particulate contamination, which can cause fouling within the condensation equipment and reduced heat transfer efficiency. Some industrial applications where refrigerated condensers are used include the dry cleaning industry, degreasers using VOC or halogenated solvents, transfer of volatile organic liquid or petroleum products, and vapors from storage vessels.

Cold-water (non-refrigeration) condensation systems can achieve 90-99% VOC control efficiency, depending on the vapor pressures of the specific compounds. Condensation units using mechanical compression refrigeration (using CFC or HFC) can achieve 90+% VOC control efficiency, condensation units using Reverse Brayton Cycle refrigeration can achieve 98% VOC control efficiency, and condensation units using cryogenic (liquid nitrogen) cooling can achieve 99+% VOC control efficiency.

Other Control Methods

(g) Bio-filtration is a process in which a waste gas stream is passed through a bed of peat, compost, bark, soil, gravel, or other inorganic media in order to strip organic contaminant gases from the waste gas stream through the process of dissolution in the bed moisture and adsorption to the bed media. Under aerobic conditions, microorganisms naturally present in the bed oxidize the organic contaminant gases within the bed to carbon dioxide, water, and additional biomass through metabolic processes. If the temperature of the waste gas stream is too high, the gas stream must be cooled to an optimum temperature before it can be treated in the biofilter in order to maintain the viability of the microorganisms. In addition, the bed must be monitored and maintained at an optimum moisture content and pH in order to prevent cracking of the bed media and to maintain the viability of the microorganisms.

Bio-filtration systems are designed to follow three basic steps. First, a pollutant in the gas phase is passed through a biologically active packed bed. The pollutant then diffuses into the biofilm immobilized on the packing medium. Finally, microorganisms growing in the biofilm oxidize the pollutant as a primary substrate or co-metabolite and in the process convert contaminants into the benign end products of carbon dioxide, water and additional biomass.

Three primary bioreactor configurations are available to treat stationary sources of air pollution: bio-filters, bio-trickling filters, and bio-scrubbers.

(1) Bio-Filters

Bio-filters are the simplest and oldest of the three vapor-phase bioreactors and involve passing a contaminated air stream through a reactor containing biologically-active packing material. The contaminants are transferred from the air stream into a bio-film immobilized on the support media and are converted by the microorganisms into CO2, water, and additional biomass. Moister is typically supplied to the bio-film in a humid inlet waste gas stream. Packing media used in bio-filter beds can be broadly categorized as either "natural" or "synthetic". Natural media include wood chips, peat, and compost, with compost by far the most widely used. Synthetic media include activated carbon, ceramic pellets, polystyrene beads, ground tires, plastic media, and polyurethane foam. Natural organic packing media generally contain a supply of nutrients as a naturally occurring component of the packing itself. When a synthetic support medium is used, nutrients must be added for microbial growth.

(2) Bio-Trickling Filters

Bio-trickling filters are similar to bio-filters with the exception that there is a liquid nutrient medium continuously recalculating through the column. To facilitate the recirculation of the liquid phase, rigid synthetic media is used as the packing medium. Microorganisms grow primarily as a fixed film on inert packing media but may also be present in the liquid phase because they can both grow suspended in the liquid phase and because the flowing liquid imparts sufficient force to detach biomass from the solid support media. Contaminants are transferred from the air stream into the liquid phase and bio-film for subsequent degradation.

Potential disadvantages of bio-trickling filter operations include: clogging of the pore space if the filter is treating high VOC loads or if the filter is provided excess nutrients, and the need to manage the liquid stream. An additional disadvantage is that bio-trickling filters may have more difficulty treating poorly soluble compounds since the specific surface are in bio-tricking filters is generally lower.

(3) Bio-Scrubbers

Bio-scrubbers combine physical and chemical treatment with a biological treatment in two separate reactors. In the first reactor, the contaminated air stream is contacted with water in a reactor packed with inert media, resulting in contaminant transfer from the air phase to the liquid phase. The liquid is then directed into an activated sludge reactor where the contaminants are biologically degraded. The separated activated sludge tank allows the reactor to treat higher concentrations of compounds than bio-filters can handle. In addition since compound transfer and degradation occur in separate reactors, optimization of each reactor can take place separately. As with bio-trickling filters, bio-scrubbers offer greater operator control over nutrient supply, acidity, and the build-up of toxic by-products.

A potential disadvantage of bio-scrubbers is that slower growing microorganisms may be washed out of the system and disposal of excess sludge is required.

Other control options

(a) Submerged Fill

Loading losses occur in cargo carrier loading as the organic vapors are displaced as the liquid product is loaded. The organic vapors can contain residual vapors from the last product loaded, vapors transferred to the tank in a vapor balance system and vapors generated in the tank as new product is loaded. The amount of vapors generated can be controlled by the type of loading method used. In splash loading, the fill pipe is only lowered part way into the tank. This results in large amounts of turbulence in the liquid and results in close contact of the VOC with the vapor which increase emissions. The submerged fill method is an alternate filling method used to reduce the amount of vapor/liquid contact. In the submerged fill method, the fill pipe extends below the liquid surface. As the liquid is transferred to the tank, the submerged fill pipe significantly reduces turbulence, air/liquid contact and results in lower overall VOC emissions.

(b) Tank Color

Color selection can contribute to elevated emissions of VOC. Black or darker colored tanks absorb more frequencies of light. This energy is transferred to the contents of the tank as heat through conduction in the tank wall. As the liquid heats, the vapor pressure rises and potential VOC emissions increase. The reverse is true for light colored or reflective tanks.

(c) Floating Roof Tanks

VOC emissions from storage tanks may be controlled through the use of floating roof tanks. Floating tanks control VOC emissions by reducing the amount of organic vapor that is in the tank at any one time. This is accomplished by having a roof that floats on top of the liquid in the tank and is sealed in a manner that does not allow vapor loss around the edges of the floating roof. By floating the roof, no vapor zone above the liquid can form.

Step 2: Eliminate Technically Infeasible Options

There are some add-on control devices that are considered technically feasible, however, due to the relatively low PTE of VOC for each tank, there are no add-on control devices that are considered economically feasible.

Submerged fill and tank color are considered feasible control options.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Since floating roof tanks, submerged fill and tank color are considered the only feasible control options, a ranking is not necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following tables summarize other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Riverview Energy Corporation
Proposed Organic Liquid Tanks BACT

(a) VOL (as defined at 40 CFR 60.111b) tanks, T1, T2, and T6, shall use internal floating roofs.
(b) Emissions from the slop tank, T16, shall be controlled by the LP Flare at all times and the slop tank throughput shall not exceed the value shown in the table below per twelve (12) consecutive month period with compliance determined at the end of each month.
(c) Emissions from the sour water tanks, T18 - T21, shall be controlled by the Sulfur Block Flare at all times and the sour water tank throughputs shall each not exceed the values shown in the table below per twelve (12) consecutive month period with compliance determined at the end of each month.
(d) All tanks shall use white tank shells.
(e) All tanks shall use submerged filling.
(f) All tanks shall use good maintenance practices based on generally-accepted industry standards, including but not limited to API 650 Welded Steel Tanks for Oil Storage and API 653 Tank Inspection, Repair, Alteration, and Reconstruction.
(g) Tanks shall comply with the following limitations:

Tank ID	Product Stored	Storage Temperature (°F)	VOC Emissions Limit (tons/yr)	Throughput Limit (kgal/yr)
T1	Naphtha Product	ambient	1.15	-
T2	Naphtha Product	ambient	1.15	-
T3	Diesel Product	ambient	2.29	-
T4	Diesel Product	ambient	2.29	-
T5	Diesel Product	ambient	2.29	-
T6	Naphtha Product	ambient	1.15	-
	Diesel Product	ambient	0.17	-
T10	Residue	505	1E-04	-
T11	Residue	505	1E-04	-
T12	Residue	505	1E-04	-
T13	VGO	505	0.175	-
T14	VGO	505	0.175	-
T16	Slop tank	-	-	305,467
T17	Diesel Fuel	ambient	1.14E-02	-
T18	Non-Phenolic Sour Water	-	-	462,829
T19	Non-Phenolic Sour Water	-	-	462,829
T20	Non-Phenolic Sour Water	-	-	462,829
T21	Phenolic Sour Water	-	-	4,628
T22	Stripped Non-Phenolic Sour Water	ambient	0.48	-
T23	Stripped Phenolic Sour Water	ambient	0.48	-
T24	Amine Surge/Deinventory	ambient	0.48	-

Riverview Energy Corporation
Proposed Organic Liquid Tanks BACT

(a) VOL (as defined at 40 CFR 60.111b) tanks, T1, T2, and T6, shall use internal floating roofs.
(b) Emissions from the slop tank, T16, shall be controlled by the LP Flare at all times and the slop tank throughput shall not exceed the value shown in the table below per twelve (12) consecutive month period with compliance determined at the end of each month.
(c) Emissions from the sour water tanks, T18 - T21, shall be controlled by the Sulfur Block Flare at all times and the sour water tank throughputs shall each not exceed the values shown in the table below per twelve (12) consecutive month period with compliance determined at the end of each month.
(d) All tanks shall use white tank shells.
(e) All tanks shall use submerged filling.
(f) All tanks shall use good maintenance practices based on generally-accepted industry standards, including but not limited to API 650 <u>Welded Steel Tanks for Oil Storage</u> and API 653 <u>Tank Inspection, Repair, Alteration, and Reconstruction</u>.
(g) Tanks shall comply with the following limitations:

Tank ID	*Product Stored*	*Storage Temperature (°F)*	*VOC Emissions Limit (tons/yr)*	*Throughput Limit (kgal/yr)*
T25	*Fresh Amine*	*ambient*	*0.48*	*-*
T26	*Amine Containment*	*ambient*	*0.48*	*-*
EU-6005	*Emergency generator diesel fuel*	*ambient*	*1.14E-02*	*-*
EU-6008	*Emergency fire pump diesel fuel*	*ambient*	*1.14E-02*	*-*

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Capacity (gallons)
Magellan Pipeline Terminals, LP	TX-0613 94433, N134 (4/23/2012)	tanks - misc	Internal floating roof	9.0 lb/hr (8.0 ton/yr)	various from 1.68 to 14.7 million gal
An internal floating roof is the most stringent control for tanks containing Volatile Organic Liquids as defined at 40 CFR 60.111b. Therefore, this has been determined to be BACT for tanks T1, T2, and T6.					
ENI US Operating Co., Inc.	FL-0328 OCS-EPA-R4007 (10/27/2011)	Various diesel storage tanks ranging from 50 gal to 610,000 gal	Use of good maintenance practices based on the current manufacturer's specifications for each tank	0.27 ton/yr	-
This has been determined BACT for all tanks.					
Union Co. Lumber Co.	AR-0124 2348-AOP-R0 (8/3/2015)	diesel oil tanks	light color tanks	0.4 lb/hr	
This has been determined BACT for all tanks.					
Agrium	AK-0083 AQ0083CPT 06 (1/6/2015)	Two Methyl-diethanol Amine (MDEA) Storage Tanks	Submerged fill	0.002 tpy	
Submerged fill has been determined BACT for all tanks.					
In addition, the source has proposed the use of a flare for tanks T16, and T18-T21. Therefore, this has been determined to be BACT for tanks T16, and T18-T21.					
CF Industries Nitrogen	IA-0106 PN 13-037 (7/12/2013)	Diesel Belly Tanks	None	VOC: 0.1 ton/yr	various
		Methyl-diethanol Amine (MDEA) Storage Tank	Nitrogen blanket	0.1 tpy	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Capacity (gallons)
A nitrogen blanket is not considered BACT for the MDEA tanks, T24-T26. A nitrogen blanket is not a control technology for VOC emissions from a tank because the blanket does not affect the partial pressure of the stored liquid or the vapor phase concentration exhausted from the tank.					
LBC Houston	TX-0783 123325, N206 (2/6/2016)	tanks (24) vapor pressure <0.52 psia	submerged fill pipes and are painted white	0.01 tpy	
		tanks (16)	internal floating roofs with welded seams, mechanical shoe primary seals, rim-mounted secondary seals adn welded deck seams and vapor combustor	0.26 tpy for (6) and 0.15 tpy for (10) NSPS Kb 99.9% CE	
Ticona Polymers	TX-0774 123216, PSDTX1438 and GHGPSDTX (11/12/2015)	crude and methanol tanks	Submerged fill, white tanks with internal floating roofs	NSPS Kb & MACT G 6.86 tpy	
Union County Lumber Company	AR-0124 2348-AQP-R0 (8/3/2015)	diesel storage tanks	None	VOC: 0.4 lb/hr	various
		oil storage tanks	None	VOC: 0.3 lb/hr	various
Florida Power and Light Co.	FL-0346 0110037-011-AC (4/22/2014)	Three ULSD fuel oil storage tanks	Pressure relieve valves/vapor condensers, or tanks with internal floating roofs or equivalent		-
Old Dominion Electric Corp.	MD-0042 CPCN Case No. 9327 (4/8/2014)	fuel oil tanks	LAER: periodic maintenance to minimize fugitive emissions	0.001 ton/yr	80000, 150000, 75000 bbl
Indiana Gasification, LLC	IN-0166 T147-30464-00060 (6/27/2012)	Sulfuric acid tanks	fixed roof and submerged fill	none	866500 gal each
This source was never constructed and the permit was revoked. Therefore the reference is not considered in determining BACT					
Valero Refining	LA-0213 PSD-LA-619(M5) (11/17/2009)	tanks - for light materials, sour water, naphtha, raffinate	Floating roofs	Comply with 40 CFR 60, Subpart Kb or 40 CFR 63, Subpart CC	various
This reference is not considered BACT for the sour water tanks. IFR control requirements in 40 CFR 60, Subpart Kb are not applicable because the sour water stream does not contain volatile organic liquids as defined at 40 CFR 60.111b, the sour water will not emit VOC as defined at 40 CFR 51.100. Requirements of 40 CFR 63, Subpart 63 are not applicable to the sour water tanks because the sour water does not contain hazardous air pollutants listed in Table 1, Appendix to Subpart CC of Part 63.					
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Diesel Tank (Fixed Roof)	Submerged fill	VOC: 0.8 ton/yr	262,500 gal/day
		Naphtha Tank (Internal floating roof)	Submerged fill and floating roof	VOC: 0.88 ton/yr 99% CE	
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Conoco Phillips	IL-0103 06050052 (8/5/2008)	sour water tank	Internal floating roof	none	3,360,000 gal
This reference is not considered BACT for the sour water tanks at the proposed source. IFR control requirements in 40 CFR 60, Subpart Kb are not applicable because the sour water stream does not contain volatile organic liquids as defined at 40 CFR 60.111b, the sour water will not emit VOC as defined at 40 CFR 51.100. Requirements of 40 CFR 63, Subpart 63 are not applicable to the sour water tanks because the sour water does not contain hazardous air pollutants listed in Table 1, Appendix to Subpart CC of Part 63.					
Navajo Refining Co., LLC	NM-0050 PSD-NM-195-M25 (12/14/2007)	tanks - naphtha, or vol liq up to 11.0 psi	External floating roof	none	100,000 bbl thrpt (4.2 million gal)
		Sour Water Tank and Naphtha tank	External floating roof	none	20000 BBL

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Capacity (gallons)
BACT for the proposed source includes internal floating roofs for VOL tanks. External floating roofs are not considered a more restrictive control. This reference is not considered BACT for the sour water tanks at the proposed source. IFR control requirements in 40 CFR 60, Subpart Kb are not applicable because the sour water stream does not contain volatile organic liquids as defined at 40 CFR 60.111b, the sour water will not emit VOC as defined at 40 CFR 51.100. Requirements of 40 CFR 63, Subpart 63 are not applicable to the sour water tanks because the sour water does not contain hazardous air pollutants listed in Table 1, Appendix to Subpart CC of Part 63.					
Progress Energy Florida	FL-0285 PSD-FL-381, 1030011-010-AC (1/26/2007)	tanks - Distillate	None	keep records establishing vapor pressure is below 3.5KPa	3.5 million gal. (ea.)
Florida Power and Light Co.	FL-0286 PSD-FL-354, 0990646-001-AC (1/10/2007)	tanks - Distillate (ULSD)	None	keep records establishing vapor pressure is below 3.5KPa; MSDS is acceptable	6.3 million gal. (ea.)
Marathon Petroleum Co. LLC	LA-0211 PSD-LA-719 (12/27/2006)	tanks - petroleum products	fixed roof and internal floating roofs	40 CFR 63 Subpart CC	various
Citgo Refining and Chemicals Co.	TX-0478 PSD-TX-408M3 (4/20/2015)	tanks - petroleum products	None	1.6 lb/hr (3.9 tpy)	various
		tanks - petroleum products	None	4.4 lb/hr (3.3 tpy)	various
		tanks - petroleum products	None	0.8 lb/hr (1.4 tpy)	various
Continental Carbon Co.	TX-0464 P1014 (3/18/2005)	tanks - low vapor pressure oil	Fixed roof	0.01 lb/hr	NA

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (Control Technology Review; Requirements), IDEM has established the following BACT:

(a) All tanks shall use white tank shells.
(b) All tanks shall use submerged filling.
(c) All tanks shall use good maintenance practices based on generally-accepted industry standards, including but not limited to API 650 Welded Steel Tanks for Oil Storage and API 653 Tank Inspection, Repair, Alteration, and Reconstruction.
(d) Tanks shall comply with the following controls and limitations:

Tank ID	Product Stored	Storage Temperature (°F)	Vapor Pressure[1] (psia)	Throughput Limit[2] (kgal/yr)
T1	Naphtha Product	ambient	1.15	-
T2	Naphtha Product	ambient	1.15	-
T3	Diesel Product	ambient	2.29	-
T4	Diesel Product	ambient	2.29	-
T5	Diesel Product	ambient	2.29	-
T6	Naphtha Product	ambient	1.15	-
	Diesel Product	ambient	0.17	-
T10	Residue[3]	505	1E-04	-
T11	Residue	505	1E-04	-
T12	Residue	505	1E-04	-
T13	VGO	505	0.175	-

Tank ID	Product Stored	Storage Temperature (°F)	Vapor Pressure[1] (psia)	Throughput Limit[2] (kgal/yr)
T14	VGO	505	0.175	-
T16	Slop tank[4]	-	-	305,467
T17	Diesel Fuel	ambient	1.14E-02	-
T18	Non-Phenolic Sour Water[5]	-	-	462,829
T19	Non-Phenolic Sour Water	-	-	462,829
T20	Non-Phenolic Sour Water	-	-	462,829
T21	Phenolic Sour Water	-	-	4,628
T22	Stripped Non-Phenolic Sour Water	ambient	0.48	-
T23	Stripped Phenolic Sour Water	ambient	0.48	-
T24	Amine Surge/Deinventory	ambient	0.48	-
T25	Fresh Amine	ambient	0.48	-
T26	Amine Containment	ambient	0.48	-
EU-6005[6]	Emergency generator diesel fuel	ambient	1.14E-02	-
EU-6008	Emergency fire pump diesel fuel	ambient	1.14E-02	-

Notes:

1. *Vapor pressure for products stored at ambient temperature taken at the highest monthly average daily temperature for Evansville, IN from meteorological data in TANKS 4.0.9d, 78.3°F.*
2. *kgal/yr = kgal per twelve (12) consecutive month period, with compliance determined at the end of each month. kgal = 1,000 gallons*
3. *Vapor pressure at elevated storage temperature from process modeling provided by the source.*
4. *Diesel fuel taken as representative of slop oil*
5. *Vapor pressure of wastewater streams and 40% MDEA solution ("amine") taken as water at 78.3°F, Table 3-5, Perry's Chemical Engineers' Handbook, 6th Ed., because of the low partial pressures of the organic compounds.*
6. *Throughput for emergency engine fuel tanks does not include operation during emergencies.*

VOC BACT Analysis
Loading Racks

Step 1: Identify Potential Control Technologies

Cooling and Condensing System

Refrigerated condensers, also sometimes known as Vapor Recovery Units (VRUs) are used as air pollution control devices for treating emission streams with high VOC concentrations (e.g., gasoline bulk terminals, storage, etc.). Condensation is a separation technique in which one or more volatile compounds of vapor mixture are separated from remaining vapors through saturation followed by a phase change.

The reported efficiency is around 80%. Refrigerated condensers are used as air pollution control devices for treating emission streams with high VOC concentrations (usually > 5,000 ppmv). Removal efficiencies above 90% can be achieved with coolants such as chilled water, brine solutions, ammonia, special filter media, etc. depending upon the emission stream characteristics.

Thermal Oxidizer

Thermal oxidation systems operate in three (3) stages: a burner generates hot combustion gases, combustion products mix with the exhaust from the process lines, and the mixture is oxidized. Thermal incineration is performed at much higher temperatures than catalytic incineration, typically between 1200°F and 2000°F. Thermal incinerators operate at peak efficiency when oxidizing concentrated organic exhaust streams just above or below the upper and lower explosive limits. This is because the oxidation rate is directly proportional to the organic concentration, the local heat of reaction during oxidation, and the increased concentration of free radicals which participate in the oxidation reaction. Thermal oxidation destruction efficiency ranges from 95% to 99%.

Catalytic Thermal Oxidizer
This type of thermal oxidizer is a better system than the straight-shot thermal oxidizer. It uses a heated catalytic (platinum coated ceramic beads) system to destroy VOCs at a much lower temperature (around 650°F) and consumes less natural gas. A catalyst is an element or compound that speeds up a reaction at lower temperatures compared to thermal oxidation without undergoing change itself. Catalytic oxidizers require approximately 1.5 to 2.0 ft^3 of catalyst per 1000 standard ft^3 per gas flow rate. Even though this type of control system can normally reach over 98% destruction efficiency, its catalytic media is very expensive to upkeep and has to be replaced every 5 years or so. It also has an odor problem due to the lower combustion temperature.

Carbon Adsorbers
Carbon adsorbers use activated carbon to remove VOC from low to medium concentration gas stream by adsorbtion. Adsorbtion itself is a phenomenon where gas molecules passing through a bed of solid particles (e.g., activated carbon) are selectively held there by attractive forces which are weaker and less specific than those of chemical bonds. During adsorbtion, a gas molecule migrates from the gas stream to the surface of the solid when it is held by physical attraction releases energy which typically equals or exceeds the heat of condensation. Most adsorbers can be cleaned by heating to a sufficiently high temperature, usually using steam or hot combustion gases or by lowering the pressure to a low value (vacuum). This cleaning process created a waste product, which will have to be properly disposed.

VOC and acid gases can be controlled with control efficiencies greater than 90%. Common problems with carbon adsorbers can be plugging and fouling of the activated carbon exposed to wet or heavily concentrated particulate gas streams. Sources may experience significant issues with maintenance and repair that result in unacceptable downtime for the control units.

Flare
Flaring is a combustion control process for VOC's in which the waste gas stream is piped to remote, usually elevated, location (for safety reasons) and burned in an open flame in the open air using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing for nearly complete (>98%) VOC destruction. Complete combustion in VCU is governed by flame temperature, residence time in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation.

Step 2: Eliminate Technically Infeasible Options

The test for technical feasibility of any control option is whether it is both available and applicable in reducing VOC emissions. All the control technologies listed in the step 1 are considered technically feasible options.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Control Option	Expected Control Efficiency
Flare	98%
Thermal Oxidation	98%
Condenser	98%
Carbon Adsorber	95%
Cooling and Condensing Systems	80%

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Naphtha loading operation and diesel loading operation*	*Loading flare (EU-4002)*	*98% CE naphtha: 0.049 lb/kgal diesel: 1.02E-03 lb/kgal Submerged loading*	
Countrymark	IN-0244 T103-35351-00011 (12/3//2015)	Truck Loading Rack	Flare vapor combustion unit, relief stack and vapor knockout box	35 mg/liter gasoline/ethanol loaded (equivalent to 0.292 lb VOC/kgal) 0.014 lb/kgal diesel loaded 0.016 lb/kgal kerosene loaded Leak Prevention measures (including submerged loading)	
Marathon	IN-0243 T129-34987-00005 (8/14/2015)	Truck Loading Rack	vapor recovery unit (VRU)	0.159 lb/kgal gasoline/ethanol loaded 0.014 lb/kgal diesel loaded Leak Prevention measures	
Countrymark	IN-0231 T055-35558-00003 (6/30/2015)	Truck loading rack	Flare vapor combustion unit, relief stack and vapor knockout box	VOC: 0.014 lb/kgal diesel loaded Leak prevention measures	
VOC limits for gasoline loading are not comparable to naphtha, which has a lower vapor pressure. Therefore the BACT for naphtha loading is established as the lb/kgal emission factor after control by a flare with DRE equal to 98% which is consistent with a flare operating in conformance with 40 CFR 60.18. VOC limit of 0.014 lb/kgal is the most stringent for diesel loading. Therefore, it is chosen as BACT.					
Castleton Commodities (CCI)	TX-0756 116072, PSDTX1388 (6/22/2015)	Truck loading diesel	None	VOC: 1.99 lb/hr (4.53 tpy)	
Chevron Phillips	TX-0722 N178 (3/14/2014)	Loading - products vapor press < 0.5 psia	Submerged fill	0.01 lb/kgal	
Colonial Pipeline	NJ-0083 18046, BOP130002 (3/11/2014)	Loading rack - light products	VRU	40 CFR 63, Subpart R and 6B VOC: 0.42 lb/hr (1 mg/L) 95% CE	441.5 MMgal/yr
KM Liquids Terminals LLC	TX-0682 101199, N158 (6/12/2013)	Loading	VCU (If vapor pressure > 0.1 psia)	If vapor pressure > 0.1 psia, then vacuum loading rqd. Leak check 99.8% DRE (if vapor pressure >0.1 psia) 500 ppmv	
Transmontaigne	VA-0313 60242 (4/22/2010)	Loading rack - diesel	None	Only controls/limits when loading gasoline or ethanol	
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	loading rack	Vapor recovery system submerged fill	VOC: 1.7 ton/yr 0.01 lb/1000 gal diesel 0.06 lb/1000 gal naphtha 99.5% CE	172462496 gal/yr

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Chelsea Sandwich LLC	MA-0040 MBR-08-IND-007 (8/20/2008)	Loading rack - residual oil	RTO	VOC: 1.77 ton/mo (3.54 tpy) 90 % capture eff. and 99% destruction eff.	
Marathon Pipeline - Zachary Station	LA-0212 PSD-LA-721 (2/1/2007)	Loading Rack	Vapor combustor (products >1.5 psia)	VOC: 10 mg/L	

Riverview has proposed the use of a flare as BACT. A search of the RBLC shows that in addition to a flare, there are other types of control. A flare is considered top BACT for this type of operation. IDEM is aware that that the above control technologies may be able to periodically achieve control efficiencies that exceed 98% under certain operating conditions (such as 99.8%). However, BACT must be achievable on a consistent basis under normal operational conditions. BACT limitations do not necessarily reflect the highest possible control efficiency achievable by the technology on which the emission limitation is based. The permitting authority has the discretion to base the emission limitation on a control efficiency that is somewhat lower than the optimal level. There are several reasons why the permitting authority might choose to do this. One reason is that the control efficiency achievable through the use of the technology may fluctuate, so that it would not always achieve its optimal control efficiency. In that case, setting the emission limitation to reflect the highest control efficiency would make violations of the permit unavoidable. To account for this possibility, a permitting authority must be allowed a certain degree of discretion to set the emission limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the Permittee to achieve compliance consistently. While we recognize that greater than 98% may be achievable as an average during testing, IDEM allows for sources to include a safety factor, or margin of error, to allow for minor variations in the operation of the emission units and the control device.

Therefore, the proposed use of a flare with control of 98% is considered the top BACT for this operation.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

(a) The Product Loading Flare shall be designed and operated in accordance with 40 CFR 60.18.

(b) The Best Available Control Technology (PSD BACT) for VOC for the product loading rack shall be as follows:

 (1) The Product Loading Rack shall use only submerged loading.

 (2) The overall VOC control efficiency, including capture efficiency and destruction efficiency, for the Product Loading Flare shall be 98% or greater.

 (3) VOC emissions shall not exceed:

Emission Limitations	
Product	**lb/kgal**[1]
naphtha	0.049
Diesel	1.02E-03

Notes:
1. kgal = 1,000 gallons

VOC BACT Analysis
Residue Solidification Units

VCC Residue is the bottoms product of the VCC Vacuum Distillation Tower wherein Vacumm Gas Oil (VGO) is extracted for recycle. The residue is a heavy bitumen type flowable liquid at ~ 500 degree F with limited volatile organic content, i.e, sufficient only to enable pumping. A small amount of hydrocarbon is initially released. The potential VGO emissions are limited due to: 1) incorporation of VGO in the residue matrix, 2) initial quick cooling of the pastille bottom surface and hemi-spherical top surface, forming an initial hard coating and 3) reduction of VGO vapor pressure in the pastille and coating with travel along the cooling line. A limited volume of exhaust air flow is extracted from the front one-third portion of the enclosures to aid cooling.

Step 1: Identify Potential Control Technologies

Add-on controls:

There are two general categories of control methods for volatile organic compounds (VOCs): destruction methods and reclamation methods. Destruction control methods reduce the VOC concentration by high temperature oxidation into carbon dioxide and water vapor. Reclamation control methods consist of capturing VOCs for reuse or disposal. These are discussed in more detail below.

Destruction Control Methods
The destruction of organic compounds usually requires temperatures ranging from 1200°F to 2200°F for direct thermal oxidizers or 600°F to 1200°F for catalytic systems. Combustion temperature depends on the chemical composition and the desired destruction efficiency. Carbon dioxide and water vapor are the typical products of complete combustion. Turbulent mixing and combustion chamber retention times of 0.5 to 1.0 seconds are needed to obtain high destruction efficiencies.

Fume oxidizers typically need supplemental fuel. Concentrated VOC streams with high heat contents obviously require less supplementary fuel than more dilute streams. VOC streams sometimes have a heat content high enough to be self-sustaining, but a supplemental fuel-firing rate equal to about 5% of the total oxidizer heat input is usually needed to stabilize the burner flame. Natural gas is the most common fuel for VOC oxidizers, but fuel oil is an option in some circumstances.

Destruction control methods include:

(a) Thermal Oxidizer:

Thermal oxidation is the process of oxidizing VOC in a waste gas stream by raising the temperature above the VOC's auto-ignition point in the presence of oxygen for sufficient time to completely oxidize the organic contaminants to carbon dioxide and water. The residence time, temperature, flow velocity and mixing, and the oxygen concentration in the combustion chamber affect the oxidation rate and destruction efficiency. Thermal oxidizers operating costs are relatively high, since they typically require combustion of an auxiliary fuel (e.g., natural gas) to maintain combustion chamber temperature high enough to completely oxidize the contaminant gases. In general, thermal oxidizers are less efficient at treating waste gas streams with highly variable flowrates, since the variable flowrate results in varying residence times, combustion chamber temperature, and poor mixing. In addition, thermal oxidizers are also not generally cost-effective for low-concentration, high-flow organic vapor streams.

Thermal oxidizers can achieve 95-99.99+% VOC control efficiency and can be used over a wide range of organic vapor concentrations, but perform best at inlet concentrations of around 1,500-3,000 ppmv. Thermal oxidizers are typically designed to have a residence time of 0.3 to 1.0 second and combustion chamber temperatures between 1,200 and 2,000°F. In order to meet

98% or greater control or a 20 parts per million by volume (ppmv) compound exit concentration of non-halogenated organics, thermal oxidizers should typically be operated at a residence time of at least 0.75 seconds, a combustion chamber temperature of at least 1600°F, and with proper mixing. While thermal oxidation provides efficient VOC control, other pollutants such as nitrogen oxides and carbon monoxide are formed from the combustion process.

Thermal oxidizers are not generally recommended for controlling gases containing halogen- or sulfur-containing compounds, because of the formation of hydrogen chloride, hydrogen fluoride gas, sulfur dioxide, and other highly corrosive acid gases. It may be necessary to install a post-oxidation acid gas treatment system in such cases, depending on the outlet concentration. This would likely make incineration an uneconomical option. For halogenated VOC streams, a combustion temperature of 2000°F, a residence time of 1.0 second, and use of an acid gas scrubber on the outlet is recommended.

The three types of thermal oxidation systems include direct flame, recuperative, and regenerative thermal oxidizers, which are differentiated by the type of heat recovery equipment used.

(1) Direct Flame Thermal Oxidizer

A direct flame thermal oxidizer is comprised of a combustion chamber and does not include any heat recovery of exhaust air by a heat exchanger.

(2) Recuperative Thermal Oxidizer

A recuperative thermal oxidizer is comprised of the combustion chamber, a heat exchanger for preheating the untreated VOC gas stream, and, if cost-effective, a secondary energy recovery heat exchanger. In a recuperative thermal oxidizer, the untreated VOC gas stream entering the oxidizer is preheated using the heat content of the treated gas stream exiting the oxidizer using a heat exchanger, resulting in improved oxidizer efficiency and reduced auxiliary fuel usage. Recuperative thermal oxidizers usually are more economical than direct flame thermal oxidizers because they typically recover 40 to 70% of the waste heat from the exhaust gases.

(3) Regenerative Thermal Oxidizer

A regenerative thermal oxidizer typically consists of a set of 2 or 3 packed ceramic beds that are used to recover heat from hot combustion gases that are generated during combustion of the VOC gas stream and auxiliary fuel, resulting in improved oxidizer efficiency and reduced auxiliary fuel usage. An "inlet" bed is used to pre-heat the untreated VOC gas stream, an "outlet" bed is used to recover heat from the treated gas stream, and one bed is in a purge cycle. The purge cycle is needed to prevent emission spikes each time the gas flow is redirected. The oxidizer is operated on a rotating schedule, where the gas flow through the ceramic beds is redirected periodically using a set of gas flow dampers. Once the heat energy of the "inlet" ceramic bed has been depleted, the flow through the system is redirected so that the untreated VOC gas stream entering the oxidizer is directed through the previously heated "outlet" ceramic bed. Regenerative thermal oxidizers have much higher heat recovery efficiencies than recuperative thermal oxidizers, recovering 85 to 95% of the heat from the treated gas stream, and therefore have lower auxiliary fuel requirements. However, compared to direct flame and recuperative thermal oxidizers, regenerative thermal oxidizers typically have higher capital (equipment and installation) costs, are larger and heavier, and have higher maintenance costs.

(b) Catalytic Oxidizer:

Catalytic oxidation is the process of oxidizing organic contaminants in a waste gas stream within a heated chamber containing a catalyst bed in the presence of oxygen for sufficient time to completely oxidize the organic contaminants to carbon dioxide and water. The catalyst is used to lower the activation energy of the oxidation reaction, enabling the oxidation to occur at lower reaction temperatures compared to thermal oxidizers. The residence time, temperature, flow velocity and mixing, the oxygen concentration, and type of catalyst used in the combustion chamber affect the oxidation rate and destruction efficiency. Catalytic oxidizers typically require combustion of an auxiliary fuel (e.g., natural gas) to maintain combustion chamber temperature high enough to completely oxidize the contaminant gases. Catalytic oxidizers operate at lower temperatures and require less fuel than thermal oxidizers, they have a smaller footprint, and they need little or no insulation. The catalyst bed is usually composed of the following: (1) the substrate, typically ceramic or metal honeycombs, grids, mesh pads, or beads; (2) the carrier, a high surface area inorganic material such as alumina that is bonded to the substrate that contains a complex pore structure; and (3) the catalyst, a thin layer of material deposited onto the carrier. The most widely used catalysts for VOC oxidation are noble metals, such as platinum, palladium and rhodium or mixtures thereof. Base metal catalysts, such as oxides of chromium, cobalt, copper, manganese, titanium, and vanadium may also be used for VOC oxidation. Similar to thermal oxidizers, catalytic oxidizers may use regenerative or recuperative heat recovery to reduce auxiliary fuel requirements, where the untreated VOC gas stream entering the catalytic oxidizer is preheated using the heat content of the treated gas stream exiting the catalytic oxidizer.

Catalytic oxidizers can achieve 90-99% VOC control efficiency, depending on the oxidizer design and waste stream characteristics. Catalytic oxidizers are typically designed to have a residence time of 0.5 seconds or less and combustion chamber temperatures between 600 and 1,200°F. Catalytic oxidation is most suited to waste gas streams with little variation in the flow rate and type and concentration of VOC to be treated. In addition, catalytic oxidizers should not be used for waste gas streams that have a high concentration of particles, silicone, sulfur, halogen compounds, and/or heavy hydrocarbons that can cause fouling or masking of the catalyst, and for waste gas streams that contain metals such as mercury, phosphorus, arsenic, antimony, bismuth, lead, zinc, and/or tin that can cause catalyst poisoning.

(c) Flare:

Flaring is the process of oxidizing VOC in a waste gas stream by piping the waste gas to a remote, usually elevated location and burning it in a flame using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing. Flares are generally categorized in two ways: (1) by the height of the flare tip (i.e., ground or elevated), and (2) by the method of enhancing mixing at the flare tip (i.e., steam-assisted, air-assisted, pressure-assisted, or non-assisted). Flares can be used to control almost any VOC stream, and can typically handle large fluctuations in VOC concentration, flow rate, heating value, and inert species content. Flaring is appropriate for continuous, batch, and variable flow vent stream applications, but the primary use is that of a safety device used to control a large volume of pollutant resulting from upset conditions. Flares have primarily been used in petroleum production, petroleum refineries, and chemical plants to control waste gas streams containing low molecular weight VOC with high heating values.

A properly operated flare can achieve 98+% VOC control efficiency when controlling emission streams with heat contents greater than 300 British thermal units per standard cubic foot (Btu/scf). If the waste gas stream has a heat content less than 300 Btu/scf, auxiliary fuel must be introduced in sufficient quantity to make up the difference. The VOC destruction efficiency of a flare depends upon the waste gas characteristics (density, flammability, heating value, and VOC component autoignition temperatures) and the combustion zone conditions (temperature, residence time, mixing, and available oxygen). While flares can provide efficient VOC control, other pollutants such as nitrogen oxides (NOx) and carbon monoxide (CO) are formed from the combustion process. Flares are not generally recommended for controlling gases containing halogen- or sulfur-containing compounds, because of the formation of hydrogen chloride, hydrogen fluoride gas, sulfur dioxide, and other highly corrosive acid gases.

Reclamation Control Methods
Organic compounds may be reclaimed by one of three possible methods: adsorption, absorption (scrubbing), or condensation. In general, the organic compounds are separated from the emission stream and reclaimed for reuse or disposal. Depending on the nature of the contaminant and the inlet concentration of the emission stream, recovery technologies can reach efficiencies of 98%.

(d) Carbon Adsorption Unit:

Carbon adsorption is a process where VOCs are removed from a waste gas stream when it is passed through a bed containing activated carbon particles, which have a highly porous structure with a large surface-to-volume ratio. Carbon adsorption systems usually operate in two phases: adsorption and desorption. During adsorption, the majority of the VOC molecules migrate from the gas stream to the surface of the activated carbon (through the activated carbon pores) where it is lightly held to the surface by weak intermolecular forces known as van der Waals' forces. As the activated carbon bed approaches saturation with VOC, its control efficiency drops, and the bed must be taken offline to be replaced or regenerated. Typically, two activated carbon beds are utilized on a rotating schedule, where a second bed (containing fresh or previously regenerated activated carbon) is brought online to continue controlling the VOC gas stream while the first bed is being replaced or regenerated. In regenerative systems, most VOC gases can be desorbed and removed from the activated carbon bed by heating the bed to a sufficiently high temperature, usually via steam or hot air, or by reducing the pressure within the bed to a sufficiently low value (vacuum desorption). The regenerated activated carbon can be reused and the VOCs that are removed from the bed can be reclaimed or destroyed.

Carbon adsorber size and purchase cost depend primarily on the gas stream volumetric flow rate, temperature, pressure, VOC composition, VOC mass loading, and moisture and particulate contents. The adsorptive capacity of an activated carbon bed for a VOC gas tends to increase with the VOC gas phase concentration, molecular weight, diffusivity, polarity, and boiling point. Carbon adsorption systems can be used for VOC gas concentrations from less than 10 ppm to approximately 10,000 ppm. Carbon adsorption systems (in general) are usually limited to waste gas streams with VOC compounds having a molecular weight of more than 50 and less than approximately 200 lb/lb-mole, since low molecular weight organics usually do not adsorb sufficiently and high molecular weight compounds are difficult to desorb and remove during the desorption cycle. Industrial applications of adsorption systems include control for dry cleaning, degreasing, paint spraying, solvent extraction, metal foil coating, paper coating, plastic film coating, printing, pharmaceuticals, rubber, linoleum, and transparent wrapping.

Carbon adsorption systems can achieve 95-99% VOC control efficiency. Carbon adsorption system control efficiency increases with reduced VOC gas stream temperatures. Therefore, high temperature VOC gas streams are typically cooled prior to entry into the activated carbon bed. Particulate matter and high moisture concentrations present in the gas stream compete with the VOC for pore space within the activated carbon and thereby reduce the VOC adsorptive capacity and control efficiency of the carbon adsorption systems. In addition, particulate matter and moisture can become entrained within the carbon bed, causing operating problems such as increased pressure drop across the bed.

(e) Gas Absorption (wet scrubber):

A wet scrubber is an absorption system in which a waste gas stream is interacted with a scrubbing fluid inside a contact chamber in order to strip particulate or gaseous pollutants from the waste gas stream through the processes of diffusion and dissolution. In many cases, an additive such as an acid, a base, or a VOC oxidizing agent is dissolved in the scrubbing fluid so that the dissolved gaseous pollutant chemically reacts with the scrubbing fluid to form a non-volatile or soluble product, thereby allowing additional gaseous pollutant to be absorbed by the scrubbing fluid. The four types of wet scrubber systems include packed towers, plate (or tray) columns, venturi scrubbers, and spray chambers. Gas and liquid flow through an absorber may be countercurrent, crosscurrent, or cocurrent. When used as an emission control technique, wet scrubbers are typically used for controlling particulate, acid gases, halogen gases, and highly soluble gases such as sulfur dioxide and ammonia.

If a wet scrubber is used for VOC control, the scrubbing fluid chosen should have a high solubility for the VOC gas, a low vapor pressure, a low viscosity, and should be relatively inexpensive. Water is the most commonly used scrubbing fluid for absorbing highly water-soluble (hydrophilic) VOC compounds such as methanol, ethanol, isopropanol, butanol, acetone, and formaldehyde. Other scrubbing fluid such as mineral oils, nonvolatile hydrocarbon oils, and aqueous solutions containing surfactants or amphiphilic block copolymers may be used for absorbing water-insoluble (hydrophobic) VOC compounds. Physical absorption is typically enhanced by lower temperatures, greater scrubbing fluid contacting time and surface area, higher scrubbing fluid to VOC ratio, and higher VOC concentrations in the gas stream.

Wet scrubber systems can achieve 70-99% VOC control efficiency, depending on the VOC solubility in the scrubbing fluid, the VOC-scrubbing fluid temperature, the scrubbing fluid contacting time and surface area, the scrubbing fluid to VOC ratio, the VOC concentration in the gas stream, and whether the scrubbing fluid contains a VOC oxidizing agent. Wet scrubber absorption system control efficiency increases with reduced VOC gas stream temperatures. Therefore, high temperature VOC gas streams are typically cooled prior to entry into the wet scrubber. When used to control VOC, the spent scrubbing fluid must be regenerated, treated, or shipped offsite for proper disposal.

(f) Condensation Unit:

Condensation is the separation of VOCs from an emission stream through a phase change, by either increasing the system pressure or, more commonly, lowering the system temperature below the dew point of the VOC vapor. Three types of condensers are used for air pollution Controls: (1) conventional non-refrigeration systems (such as cold-water direct contact condensers similar to wet scrubbers and cold-water indirect heat exchangers); (2) refrigeration systems (including mechanical compression refrigeration using chlorofluorocarbons (CFCs) and hydrofluorocarbons (HFCs) and Reverse Brayton Cycle refrigeration); and (3) cryogenic systems that utilize liquid nitrogen (including direct contact condensers and indirect heat exchangers).

Condensation units control VOC more efficiently when they are used for gas streams containing high concentrations of VOC and with low exhaust volumes. Condensation units are typically utilized at sources where there is a significant cost benefit to recovering the organic liquid for reuse, where the recovered organic liquids do not contain multiple organic compounds or water that require separation, and where the heat content of gas stream will not overload the refrigeration system. In addition, condensation units are typically used only on gas streams that have little or no particulate contamination, which can cause fouling within the condensation equipment and reduced heat transfer efficiency. Some industrial applications where refrigerated condensers are used include the dry cleaning industry, degreasers using VOC or halogenated solvents, transfer of volatile organic liquid or petroleum products, and vapors from storage vessels.

Cold-water (non-refrigeration) condensation systems can achieve 90-99% VOC control efficiency, depending on the vapor pressures of the specific compounds. Condensation units using mechanical compression refrigeration (using CFC or HFC) can achieve 90+% VOC control efficiency, condensation units using Reverse Brayton Cycle refrigeration can achieve 98% VOC control efficiency, and condensation units using cryogenic (liquid nitrogen) cooling can achieve 99+% VOC control efficiency.

Other Control Methods

(g) Bio-filtration is a process in which a waste gas stream is passed through a bed of peat, compost, bark, soil, gravel, or other inorganic media in order to strip organic contaminant gases from the waste gas stream through the process of dissolution in the bed moisture and adsorption to the bed media. Under aerobic conditions, microorganisms naturally present in the bed oxidize the organic contaminant gases within the bed to carbon dioxide, water, and additional biomass through metabolic processes. If the temperature of the waste gas stream is too high, the gas stream must be cooled to an optimum temperature before it can be treated in the biofilter in order to maintain the viability of the microorganisms. In addition, the bed must be monitored and maintained at an optimum moisture content and pH in order to prevent cracking of the bed media and to maintain the viability of the microorganisms.

Bio-filtration systems are designed to follow three basic steps. First, a pollutant in the gas phase is passed through a biologically active packed bed. The pollutant then diffuses into the biofilm immobilized on the packing medium. Finally, microorganisms growing in the biofilm oxidize the pollutant as a primary substrate or co-metabolite and in the process convert contaminants into the benign end products of carbon dioxide, water and additional biomass.

Three primary bioreactor configurations are available to treat stationary sources of air pollution: bio-filters, bio-trickling filters, and bio-scrubbers.

(1) Bio-Filters

Bio-filters are the simplest and oldest of the three vapor-phase bioreactors and involve passing a contaminated air stream through a reactor containing biologically-active packing material. The contaminants are transferred from the air stream into a bio-film immobilized on the support media and are converted by the microorganisms into CO2, water, and additional biomass. Moister is typically supplied to the bio-film in a humid inlet waste gas stream. Packing media used in bio-filter beds can be broadly categorized as either "natural" or "synthetic". Natural media include wood chips, peat, and compost, with compost by far the most widely used. Synthetic media include activated carbon, ceramic pellets, polystyrene beads, ground tires, plastic media, and polyurethane foam. Natural organic packing media generally contain a supply of nutrients as a naturally occurring component of the packing itself. When a synthetic support medium is used, nutrients must be added for microbial growth.

(2) Bio-Trickling Filters

Bio-trickling filters are similar to bio-filters with the exception that there is a liquid nutrient medium continuously recalculating through the column. To facilitate the recirculation of the liquid phase, rigid synthetic media is used as the packing medium. Microorganisms grow primarily as a fixed film on inert packing media but may also be present in the liquid phase because they can both grow suspended in the liquid phase and because the flowing liquid imparts sufficient force to detach biomass from the solid support media. Contaminants are transferred from the air stream into the liquid phase and bio-film for subsequent degradation.

Potential disadvantages of bio-trickling filter operations include: clogging of the pore space if the filter is treating high VOC loads or if the filter is provided excess nutrients, and the need to manage the liquid stream. An additional disadvantage is that bio-trickling filters may have more difficulty treating poorly soluble compounds since the specific surface are in bio-tricking filters is generally lower.

(3) Bio-Scrubbers

Bio-scrubbers combine physical and chemical treatment with a biological treatment in two separate reactors. In the first reactor, the contaminated air stream is contacted with water in a reactor packed with inert media, resulting in contaminant transfer from the air phase to the liquid phase. The liquid is then directed into an activated sludge reactor where the contaminants are biologically degraded. The separated activated sludge tank allows the reactor to treat higher concentrations of compounds than bio-filters can handle. In addition since compound transfer and degradation occur in separate reactors, optimization of each reactor can take place separately. As with bio-trickling filters, bio-scrubbers offer greater operator control over nutrient supply, acidity, and the build-up of toxic by-products.

A potential disadvantage of bio-scrubbers is that slower growing microorganisms may be washed out of the system and disposal of excess sludge is required.

Step 2: Eliminate Technically Infeasible Options

There are some add-on control devices that are considered technically feasible, however, due to the relatively low PTE of VOC for each unit, there are no add-on control devices that are considered economically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no technically feasible control options.

Step 4: Evaluate the Most Effective Controls and Document the Results

A search in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) did not produce any results for this type of unit.

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

BACT shall be the following:

(a) VOC emissions from residue solidification unit EU-5001a-5001d (stack S-5001) shall not exceed 1.40 lb/hr.

(b) VOC emissions from residue solidification unit EU-5002a-5002d (stack S-5002) shall not exceed 1.40 lb/hr.

(c) VOC emissions from residue solidification unit EU-5003a-5003d (stack S-5003) shall not exceed 1.40 lb/hr.

(d) VOC emissions from residue solidification unit EU-5004a-5004d (stack S-5004) shall not exceed 1.40 lb/hr.

Particulate (PM, PM_{10} and $PM_{2.5}$) BACT Analysis
Cooling Tower

Step 1: Identify Potential Control Technologies

PM emissions from cooling towers are typically controlled through one of the following mechanisms:

(1) Drift eliminators.
(2) Minimizing total dissolved solids (TDS).

Step 2: Eliminate Technically Infeasible Options:

For the cooling tower, the above listed control technologies are considered technically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The control technologies for cooling towers are ranked as follows:

(1) Drift eliminators.
(2) Minimization of total dissolved solids (TDS).

Step 4: Evaluate the Most Effective Controls and Document the Results

The following tables summarize other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Cooling Tower

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*3 Cell Cooling Tower*	*Drift Eliminator*	*PM/PM10/PM2.5: 0.0005% drift 2,395 mg/l TDS VOC: 1.34 lb/hr*	*10,667 GPM, each*
South Louisiana Methanol LP	LA-0312 PSD-LA-780(M1) (6/30/2017) (draft)	ECT-14 - Econamine Cooling tower (EQT0018)	HE drift eliminators 0.0005% drift 2,660 ppm TDS	PM10: 0.44 tpy	29,120 gpm (ea of 3 cells)
				PM2.5: 0.01 tpy	
		CT-13 - cooling tower (EQT0007)		PM10: 0.96 lb/hr 3.50 tpy	231,000 gpm (each of 18 cells)
				PM2.5: 0.01 lb/hr 0.02 tpy	
Indorama Ventures Olefins Inc	LA-0314 PSD-LA-813 (8/3/2016)	cooling towers - 007	drift eliminators	PM10/PM2.5: 0.0005% drift 1400 ppm tds	86,500 gpm
			monitoring req'd by 40 CFR 63, subpart XX	VOC, no limit	
Lake Charles Methanol LLC	LA-0305 PSD-LA-803(M1) (6/30/2016)	cooling towers: unit A	drift eliminators	PM10/PM2.5: 0.0005% drift	241,843 gpm
		cooling towers: unit B			201,196 gpm
		cooling towers: unit C			72,531 gpm
PM/PM10/PM2.5 requirement of 0.0005% drift is determined to be BACT. Specification of circulating water TDS are not applied consistently and TDS may vary with water supply characteristics tower cycles of concentration, so the TDS limitation is chosen as a worst case for cooling tower operations.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Exxon Mobil Oil Corp	TX-0832 PSDTX768M1, PSDTX799, PSDTX802 (1/9/2018) (draft)	cooling towers	drift eliminators	PM/PM10/PM2.5 control, no limit	-
Total Petrochemicals & Refining USA, Inc	TX-0815 122353, PSDTX1426, GHGPSDTX114, (1/17/2017)	cooling tower	drift eliminator	PM10 control, no limit	-
			cooling water VOC concentration non-contact	27.9 tpy	
Methanex USA LLC	LA-0317 PSD-LA-761(M4) (12/22/2016)	cooling towers (I-CT-621, II-CT-621)	drift eliminators	PM10/PM2.5: 0.001% drift	66,000 gpm (ea)
Sasol Chemicals (USA) Inc	LA-0319 PSD-LA-814 (9/1/2016)	cooling tower y12-800	complying with 40 CFR 63.104	VOC, no limit	-
	LA-0288 PSD-LA-778 (5/23/2014)	ASU cooling tower (EQT 636)	HE drift eliminators and low TDS water	PM10/PM2.5: 7.4 tpy 0.001% drift 1708 mg/l TDS (ann avg)	197,689 gpm
		process cooling towers (EQT 634 &635)		PM10/PM2.5: 6.99 tpy 0.001% drift 1724 mg/l TDS (ann avg)	184,920 gpm, ea
	The GTL project was reportedly cancelled in November 2017, therefore this entry is not considered to represent BACT for the proposed source.				
	LA-0301 PSD-LA-779 (5/23/2014)	cooling tower (EQT 979)	weekly TDS measurement, avg TDS w/ mfr's drift rate and design circ to calculate emissions	PM10/PM2.5: 20.47 tpy	358,000 gpm
	LA-0302 PSD-LA-779 (5/23/2014)	cooling tower (EQT 1011)		PM10/PM2.5: 1.71 tpy	156,000 gpm
Equistar Chemicals LP	LA-0295 PSD-LA-806 (7/12/2016)	CGP unit cooling tower (3-03, EQT 15)	monthly monitoring	VOC: 0.13 lb/hr (included in combined cooling tower cap of 12.29 tpy)	3,000 gpm
Flint Hills Resources Houston Chemical LLC	TX-0803 18999, PSDTX755M1, N216 (7/12/2016)	cooling tower	drift eliminators	PM10/PM2.5: 0.001% drift	-
	TX-0801 GHGPSDTX137 (6/24/2016)		design value	CO2e: 0.005% drift	
Flopam Inc	LA-0318 PSD-LA-747(M5) (1/7/2016)	cooling towers	integrated drift eliminators	PM10, no limit	-

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Ticona Polymers Inc	TX-0774 123316, PSDTX1438, GHGPSDTX (11/12/2015)	cooling tower	drift eliminators meeting 0.001% drift	PM10: 3.07 tpy	10,400 (presumed gpm)
				PM2.5: 0.01 tpy	
			minimize VOC leaks into cooling water	VOC: 3.64 tpy	
			minimize methane leaks into cooling tower	CO2e: 420 tpy	
The Dow Chemicals Co	TX-0754 100787, PSDTX1314 M1 (7/10/2015)	cooling tower	non-contact design, drift eliminators meeting 0.005%	VOC: 0.05ppm in return to tower	75,000 gpm
Castleton Commodities Int'l Corpus Christie	TX-0756 116072, PSDTX1388 (6/19/2015)	cooling tower	no contact, low drift	VOC: 0.6 lb/hr 2.63 tpy	15,000 gpm
Phillips 66 Co	IL-0115 06050052 (1/23/2015)	cooling water tower (CWT-26)	drift eliminators and monitoring program	VOC: 0.005% (12 mo total) 1.10 tpy (12 mo total)	12,000 gpm
Formosa Plastics Corporation	TX-0703 107520, PSDTX1384 (8/4/2014)	Cooling Tower	Drift Eliminator	PM2.5: 0.001% Drift	-
			monthly VOC monitoring by TCEQ El Paso method)	VOC: no limits	
C3 Petrochemicals LLC	TX-0744 PSD-TX-1342-GHG (6/12/2014)	Cooling Tower	-	CO2e	-
Natgasoline LLC	TX-0657 107764, PSDTX1340 (5/16/2014)	Cooling Tower	Monthly monitoring VOC	VOC: 0.08 ppmw and 3.3 tpy	99 MG/yr
			Drift Eliminator, 0.001% drift	PM: 82.57 tpy	
				PM10: 1.28 tpy	
				PM2.5: 0.03 tpy	
Big Lake Fuels LLC	LA-0315 PSD-LA-781 (5/23/2014) (draft)	cooling tower	HE drift eliminator	PM10: 0.39 lb/hr 1.73 tpy	6,472,902 gpm
				PM2.5: 0.24 lb/hr 1.04 tpy	
			monthly VOC monitoring	VOC: 4.53 lb/hr 19.85 tpy	
Emberclear GTL MS LLC	MS-0092 0040-00055 (5/8/2014)	cooling tower, induced draft	HE drift eliminator	PM/PM10/PM2.5: 0.001% drift	1,420 gpm
			monthly strippable VOC monitoring, modified El Paso method	VOC: 0.70 lb VOC/MMgal (12 mo avg)	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Valero Refining New Orleans LLC	LA-0246 PSD-LA-619(M6) (12/31/2010)	EQT0010 - Cooling Tower 403	Monitoring VOC concentration	VOC: 76.0 lb/hr	61,250 gpm
			Drift Eliminator	PM10: 1.2 lb/hr	
		EQT0244 - New West Cooling Tower	Monitoring VOC concentration	VOC: 49.63 lb/hr	40,000 gpm
			Drift Eliminator	PM10: 0.08 lb/hr	
		EQT0035 - cooling tower CT-600	Monitoring VOC concentration	VOC: 55.84 lb/hr	45,000 gpm
			Drift Eliminator	PM10: 0.09 lb/hr	
		EQT0243 - HCU cooling tower	Monitoring VOC concentration	VOC: 62.04 lb/hr	50,000 gpm
			Drift Eliminator	PM10: 0.10 lb/hr	
Sabina Petrochemicals LLC	TX-0575 41945, N018M1 (8/20/2010)	Cooling Tower	noncontact design, Monthly monitoring of VOC (El Paso method)	VOC: 13.4 tpy	73,000 gpm

Step 5: Select BACT

IDEM, OAQ has established BACT for the cooling towers as:

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

(a) PM, PM10, and PM2.5 emissions from the cooling tower (EU-6001, EU-6002 and EU-6003) shall be controlled by the use of drift eliminators with a maximum drift rate of no more than 0.0005%.

(b) Total dissolved solids (TDS) in the circulating cooling water shall not exceed 2,395 mg/l.

(c) VOC emissions from the cooling towers (EU-6001, EU-6002 and EU-6003) shall not exceed 1.34 lb/hr.

BACT Analysis
Emergency Engines - PM/PM10/PM2.5, NOx, SO2, VOC, CO and CO2e

Step 1: Identify Potential Control Technologies

PM/PM10/PM2.5, NOx, SO2, VOC, CO and CO2e emissions can be controlled with the following control technologies:

(1) Good Combustion Practices
(2) Low sulfur diesel

Step 2: Eliminate Technically Infeasible Options

Good Combustion Practices is the only technically feasible option.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There are no add-on control devices that are considered feasible; therefore no ranking is necessary.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Emergency Generators

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (hp)
Riverview Energy	*Proposed*	*Emergency Diesel Generator*	*Good combustion practices*	*PM/PM10/PM2.5: 0.20 g/kW-hr SO2: 15 ppm S in fuel NOx + NMHC: 6.40 g/kW-hr CO: 3.50 g/kW-hr CO2e: 811 tons per 12-month consecutive period*	2,800
		Emergency Diesel Fire Pump	*Good combustion practices*	*PM/PM10/PM2.5: 0.20 g/kW-hr SO2: 15 ppm S in fuel NOx+NMHC: 4.00 g/kW-hr CO: 3.50 g/kW-hr CO2e: 217 tons per 12-month consecutive period*	750
Standards applicable to stationary RICE are highly variable, depending on model year, power output, and service category. In general, the requirements of the NSPS, 40 CFR 60, Subpart IIII are recognized as the most restrictive limitations for new compression ignition stationary RICE.					
Florida Power & Light	FL-0356 0930117-001-AC (3/9/2016)	ULSD Emergency generators	ULSD	BACT limits equal to NSPS Subpart IIII limits. Will use IIII certified engine. CO: 3.5 g/KW-hr PM: 0.2 g/KW-hr SO2: 0.0015% S in ULSD	
		Diesel-Fired Emergency Fire pump engine	ULSD	BACT limits equal to NSPS Subpart IIII limits. Will use IIII certified engine. CO: 3.5 g/KW-hr PM: 0.2 g/KW-hr 0.0015% S in ULSD	
Grain Processing Corp.	IN-0234 T027-35177-00046 (12/8/2015)	Diesel-Fired Emergency Fire pump engine	Good combustion practices	1,128 gallons diesel/yr CO: 2.01 g/hp-hr PM/PM10/PM2.5: 0.16 g/hp-hr NOx: 9.5 g/hp-hr 0.0015% S in ULSD VOC: 0.05 g/hp-hr	425 hp

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (hp)
Mattawoman Energy	MD-0045 PSC Case No. 9330 (11/13/2015)	Diesel-fired emergency generator	Good combustion practices and ULSD	40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ CO: 3.5 g/KW-hr (converts to 2.63 g/hp-hr) PM: 0.2 g/KW-hr (converts to 0.15 g/hp-hr) PM10/PM2.5: 0.18 g/hp-hr NOx: 6.4 g/KW-hr (converts to 4.8 g/hp-hr) Sulfuric Acid Mist: 0.007 g/hp-hr	
Corrigan OSB	TX-0770 128854, PSDTX1446, GHGPSDT (10/23/2015)	Diesel-Fired Emergency Fire pump engine	Good combustion practices with clean burning fuel and limited operating hours	CO: 0.06 tpy CO2e: 335 tpy	1.4 MMBtu/hr
Florida Power & Light	FL-0354 0110037-013-AC (8/25/2015)	Diesel-Fired Emergency Fire pump engine	ULSD	BACT limits equal to NSPS Subpart IIII limits. CO: 3.5 g/KW-hr (converts to 2.63 g/hp-hr) PM: 0.2 g/KW-hr (converts to 0.15 g/hp-hr) NOx: 4.0 g/kw-hr (converts to 3.0 g/hp-hr) 0.0015% S in ULSD	29 MMBtu/hr (300 hp)
BASF	TX-0728 118239, N200 (4/1/2015)	emergency diesel generator	Hours of operation (52 hr/yr non-emergency) Tier II engine	NSPS & NESHAP CO: 0.2 tpy (0.0126 g/hp-hr) NOx: 0.35 tpy (0.0218 g/hp-hr) LAER PM10/PM2.5: 0.15 lb/hr (0.01 tpy) VOC: 0.7 lb/hr 0.02 tpy	1500
			This plant has not yet begun operation. Therefore, compliance with these limits has not been demonstrated. ULSD (15 ppmw)	SO2: 0.61 lb/hr (0.02 tpy)	
Tinker AFB	OK-0164 2009-394-C M-2 PSD (1/8/2015)	Diesel-Fired Emergency Fire pump engine	ULSD and Good combustion practices	100 hr/yr operation VOC: 0.15 g/hp-hr CO2e: 44.0 tpy	
Moundsville Power	WV-0025 R14-0030 (11/21/2014)	Diesel-fired emergency generator	None	CO: 2.6 g/hp-hr PM2.5: 0.15 g/hp-hr NOx: 4.8 g/hp-hr NMHC+NOx VOC: 1.24 lb/hr	2015.7 hp

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (hp)
		Fire Pump Engine	None	Limited to 100 Hours/year CO: 1.44 lb/hr PM2.5: 0.15 g/hp-hr NOx: 3.0 g/hp-hr NMHC+NOx VOC: 0.17 lb/hr CO2e: 309.0 lb/hr	251 hp
BP Amoco Chemical	SC-0170 0420-0029-CU (11/7/2014)	Emergency generator	ULSD	100 hr/yr non-emergency use, tier 3 emission standards	
Keys Energy Center	MD-0046 PSC Case No. 9297 (10/31/2014)	Fire Pump Engine	Good combustion practices and ULSD	NSPS IIII CO: 3.5 g/kw-hr PM: 0.2 g/kw-hr PM10: 0.18 g/kw-hr NOx: 4.0 g/kw-hr	300 hp
Adarko Petroleum Corp.	FL-0347 OCS-EPA-R4015 (9/16/2014)	emergency diesel generator	Use of good combustion practices based on the most recent manufacturer's specifications	No limits listed	3300
Cronus Chemicals	IL-0114 13060007 (9/5/2014)	Emergency generator	ULSD	PM/ PM10/PM2.5: 0.1 g/KW-hr NOx: 0.67 g/KW-hr VOC: 0.4 g/KW-hr (converts to 0.3 g/hp-hr) CO: 3.5 g/KW-hr	
These limits cite Tier 4 standards for nonroad engines in model year 2014 and earlier (40 CFR 1039.102, Table 7). This reference is not considered applicable to new engines proposed for Riverview Energy Corp. The definition of nonroad engine in part 1039 excludes stationary engines, and the emission standards in that part are not applicable unless referenced in another part.					
Formosa Plastics Corporation	TX-0703 107520, PSDTX1384 (8/4/2014)	Emergency generators	Good combustion	40 CFR 60 Subpart IIII requirements 40 CFR 80.510	
Nucor Steel	AL-0301 413-0033-X014 - X020 (7/22/2014)	Diesel-fired emergency generator	None	CO: 0.0055 lb/hp-hr (converts to 2.5 g/hp-hr) PM: 0.0007 lb/hp-hr (converts to 0.32 g/hp-hr) NOx: 0.015 lb/hp-hr (converts to 6.8 g/hp-hr)	
Nucor Steel	AL-0275 413-0033 (7/22/2014)	Diesel-fired emergency generator	None	CO: 0.0055 lb/hp-hr (converts to 2.5 g/hp-hr) PM: 0.0007 lb/hp-hr (converts to 0.32 g/hp-hr) NOx: 0.015 lb/hp-hr (converts to 6.8 g/hp-hr)	
Constellation Power	MD-0043 PSC Case No. 9136 (7/1/2014)	Emergency generator	Good combustion practices	40 CFR 60 Subpart IIII requirements ULSD, limited hours PM: 0.15 g/hp-hr PM10/PM2.5: 0.17 g/hp-hr NOx: 4.8 g/hp-hr & 6.4 g/kw-hr	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (hp)
Dominion Cove Point Terminal	MD-0044 PSC Case No. 9138 (6/9/2014)	Emergency generator	Good combustion practices	40 CFR 60 Subpart III requirements ULSD CO: 2.6 g/hp-hr & 3.49 g/kw-hr PM: 0.15 g/hp-hr & 0.2 kw-hr PM10/PM2.5: 0.17 g/hp-hr & 0.23 g/kw-hr NOx (LAER): 4.8 g/hp-hr & 6.4 g/kw-hr VOC (LAER): 4.8 g/hp-hr & 6.4 g/kw-hr	
Midwest Fertilizer	IN-0173 T129-33576-00059 (6/4/2014)	diesel-fired emergency generator	Good combustion practices and energy efficiency	hours of operation <500 hr/yr PM/PM10/PM2.5: 0.15 g/hp-hr NOx: 4.46 g/hp-hr CO: 2.61 g/hp-hr VOC: 0.31 g/hp-hr GHG: 526.39 g/hp-hr	
Midwest Fertilizer	IN-0173 T129-33576-00059 (6/4/2014)	Diesel-Fired Emergency Firewater Pump	Good combustion practices and energy efficiency	hours of operation <500 hr/yr PM/PM10/PM2.5: 0.15 g/hp-hr NOx: 2.83 g/hp-hr CO: 2.60 g/hp-hr VOC: 0.141 g/hp-hr GHG: 527.4 g/hp-hr	
Mag Pellet	IN-0185 T181-33965-00054 (4/24/2014)	Diesel fire pump	Good combustion practices	500 hr/yr PM/PM10/PM2.5: 0.15 g/hp-hr NOx: 3.0 g/hp-hr SO2: 0.29 lb/MMBtu CO2e: 31.11	
Ohio Valley Resources	IN-0179 T147-32322-00062 (9/25/2013)	Diesel-fired emergency generator	Good combustion practices	hours of operation <200 hr/yr PM/PM10/PM2.5: 0.15 g/hp-hr NOx: 4.46 g/hp-hr CO: 2.61 g/hp-hr VOC: 0.31 g/hp-hr GHG: 526.39 g/hp-hr	
Ohio Valley Resources	IN-0179 T147-32322-00062 (9/25/2013)	Diesel-Fired Emergency Firewater Pump	Good combustion practices	hours of operation <200 hr/yr PM/PM10/PM2.5: 0.15 g/hp-hr NOx: 2.86 g/hp-hr CO: 2.60 g/hp-hr VOC: 0.141 g/hp-hr GHG: 527.4 g/hp-hr	
DynoNobel Louisiana Ammonia	LA-0272 PSD-LA-768 (3/27/2013)	emergency diesel generator	500 hr/yr limit Energy efficiency measures good combustion practices	Comply with 40 CFR 60, Subpart IIII CO: 3.5 g/Kw-hr (2.6 g/hp-hr) NOx: 6.4 g/Kw-hr (4.77 g/hp-hr) PM10/PM2.5: 0.2 g/Kw-hr (0.15 g/hp-hr) VOC: 6.4 g/Kw-hr (4.77 g/hp-hr)	1200

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (hp)
				CO2e: energy efficiency	
St. Joseph Energy Center	IN-0158 T141-31003-00579 (12/3/2012)	emergency diesel generators (3)	Good engineering design and fuel efficient design post combustion carbon control	CO2e: 1186 tpy (combined)	2012 and 2 @ 1006
			Combustion design controls and 500 hr/yr (each)	CO: 2.6 g/hp-hr NOx: 4.8 g/hp-hr PM/ PM10/PM2.5: 0.15 g/hp-hr	
			ULSD and 500 hr/yr (each)	SO2: 0.012 lb/hr VOC: 1.04 lb/hr	
		firewater pump diesel engines (2)	Good engineering design and fuel efficient design	CO2e: 172 tpy (combined)	371 (each)
			Combustion design controls and 500 hr/yr (each)	CO: 2.6 g/hp-hr NOx: 3.0 g/hp-hr PM/ PM10/PM2.5: 0.15 g/hp-hr	
Indiana Gasification - IN	IN-0166 / T147-30464-00060 (6/27/2012)	Fuel oil Generators (2)	none	< 52 non-emergency hrs/yr PM/PM10/PM2.5: 15 ppm sulfur SO2: 15 ppm CO: 84.0 tpy	1341 hp
		fire pump engine (3 engines)	Good Combustion Practices and limited hours of non-emergency operation	Good Combustion Practices and limited hours of non-emergency operation SO2: 15 ppm sulfur CO2: 84.0 tpy	575 hp each
Entergy Louisiana LLC	LA-0254 PSD LA-752 (8/16/2011)	emergency diesel generator	Proper operation and good combustion practices	CO2: 163.0 lb/MMBtu CH4: 0.0061 lb/MMBtu N2O: 0.0014 lb/MMBtu	1250
			ULSD and good combustion practices	CO: 2.6 g/hp-hr PM10/PM2.5: 0.15 g/hp-hr VOC: 1.0 g/hp-hr	
		emergency fire pump	Proper operation and good combustion practices	CO2: 163.0 lb/MMBtu CH4: 0.0061 lb/MMBtu N2O: 0.0014 lb/MMBtu	350
			ULSD and good combustion practices	CO: 2.6 g/hp-hr PM10/PM2.5: 0.15 g/hp-hr VOC: 1.0 g/hp-hr	
Lake Charles Cogen, LLC	LA-0231 PSD-LA-742 (6/22/2009)	emergency diesel generator	None	Comply with NSPS CO: 0.62 lb/hr NOx: 17.09 lb/hr PM10: 0.06 lb/hr SO2: 0.01 lb/hr	1341 (each)
		fire water diesel pumps (3)	None	Comply with NSPS CO: 0.37 lb/hr NOx: 6.02 lb/hr PM10: 0.08 lb/hr SO2: 0.01 lb/hr	575 (each)

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (hp)
Associated Electric Coop.	OK-0129 2007-115-C M-1 PSD (1/23/2009)	emergency diesel generator	Low sulfur diesel 0.05% S and good combustion	Comply with NSPS CO: 12.66 lb/hr (3.5 g/Kw-hr) NOx: 23.15 lb/hr (6.4 g/KW-h) PM10: 0.72 lb/hr (0.2 g/kW-h) SO2: 0.89 lb/hr VOC: 1.55 lb/hr	2200
		emergency diesel fire pump	Low sulfur diesel and good combustion	Comply with NSPS CO: 2.6 g/hp-hr NOx: 4.59 lb/hr (7.8 g/hp-hr) PM10: 0.24 lb/hr (0.4 g/hp-h) SO2: 0.11 lb/hr VOC: 0.66 lb/hr	267
Cornell University	NY-0101 NY-0001 (3/12/2008)	emergency diesel generators	800 hr/yr limit (combined for both) Ultra-low sulfur diesel at 15 ppm	NSPS PM/PM10/PM2.5: 0.19 lb/hr, 20 % opacity H2SO4: 0.002 lb/hr	1000 kW
Western Farmers Electric Coop	OK-0118 97-058-C M-2 PSD (2/9/2007)	emergency diesel generator and fire pump	Good combustion practices and limited hours	Low sulfur fuel (< 0.5%)	not listed

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

(a)

Emission Unit	ID	Pollutant	Limitation	
Emergency Diesel Generator	EU-6006	PM	0.20 g/kW-hr	Use of Tier II diesel engine
		PM10	0.20 g/kW-hr	
		PM2.5	0.20 g/kW-hr	
		SO_2	15 ppm in fuel	
		NOx + NMHC	6.40 g/kW-hr	
		CO	3.50 g/kW-hr	
		Opacity	Acceleration: 20% Lugging: 15% Peak: 50%	
		CO_2e	811 tons per twelve (12) consecutive month period with compliance determined at the end of each month	
Emergency Diesel Firewater pump	EU-6009	PM	0.20 g/kW-hr	Engine that complies with Table 4, 40 CFR 60, Subpart IIII
		PM10	0.20 g/kW-hr	
		PM2.5	0.20 g/kW-hr	
		SO_2	15 ppm in fuel	
		NOx + NMHC	4.00 g/kW-hr	
		CO	3.50 g/kW-hr	
		CO_2e	217 tons per twelve (12) condecutive month period with compliance determined at the end of each month	

(c) Emergency generator (EU-6006) and emergency fire pump (EU-6009) shall use good combustion practices and shall use energy efficiency. Use of good combustion practices and energy efficiency is defined as operation of engines certified to meet applicable emissions standards in accordance with the manufacturers' recommendations for operation and maintenance or according to a maintenance plan that complies with 40 CFR 60.4211(g). Good combustion practices may include but are not limited to the following:

(1) Prepare and maintain a preventive maintenance plan.

(2) Change oil and filter every 500 hours of operation or annually, whichever comes first.

(3) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

(5) During periods of startup the Permittee must minimize the engine's time spent at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes.

BACT Analysis
Hydrogen Plant

NOx

Step 1: Identify Potential Control Technologies

NOx emissions can be controlled with the following control technologies:

Post-combustion controls:
(1) Selective Catalytic Reduction (SCR)
(2) Selective Non-Catalytic Reduction (SNCR)

Combustion controls:
(3) Low NOx Burner (LNB)/Ultra low-Nox burner (ULNB)
(4) Flue Gas Recirculation (FGR)

Selective Catalytic Reduction (SCR)
Selective Catalytic Reduction (SCR) process involves the mixing of anhydrous or aqueous ammonia vapor with flue gas and passing the mixture through a catalytic reactor to reduce NO_X to water and N_2. Under optimal conditions, SCR has a removal efficiency up to 90% when used on steady state processes. The efficiency of removal will be reduced for processes that are not stable or require frequent changes in the mode of operation.

The most important factor affecting SCR efficiency is temperature. SCR can operate in a flue gas window ranging from 480°F to 800°F, although the optimum temperature range depends on the type of catalyst and the flue gas composition. In this particular service, the minimum target temperature is approximately 750°F. Temperatures below the optimum decrease catalyst activity and allow NH3 to slip through; above the optimum range, ammonia will oxidize to form additional NOx. SCR efficiency is also largely dependent on the stoichiometric molar ratio of NH3:NOx; variation of the ideal 1:1 ratio to 0.5:1 ratio can reduce the removal efficiency to 50%.

Selective Non-Catalytic Reduction (SNCR)
With selective non-catalytic reduction (SNCR), NO_X is selectively removed by the injection of ammonia or urea into the flue gas at an appropriate temperature window of 1600°F to 2000°F, without employing a catalyst. Similar to SCR without a catalyst bed, the injected chemicals selectively reduce the NO_X to molecular nitrogen and water. This approach avoids the problem related to catalyst fouling but the temperature window and reagent mixing residence time is critical for conducting the necessary chemical reaction.

At the proper temperature, urea decomposes to produce ammonia which is responsible for NO_X reduction. At a higher temperature, the rate of competing reactions for the direct oxidation of ammonia that forms NOx becomes significant. At a lower temperature, the rates of NO_X reduction reactions become too slow resulting in urea slip (i.e. emissions of unreacted urea).

Optimal implementation of SNCR requires the employment of an injection system that can accomplish thorough reagent/gas mixing within the temperature window while accommodating spatial and production rate temperature variability in the gas stream. The attainment of maximum NO_X control performance requires that the furnace exhibit a favorable opportunity for the application of this technology relative to the location of the reaction temperature range and steady operation within that temperature window.

Low NOx Burners (LNB)
Using LNB can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature.

Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 50% but under certain conditions, higher reductions are possible.

Flue Gas Recirculation (FGR)
Recirculating a portion of the flue gas to the combustion zone can lower the peak flame temperature and result in reduced thermal NOx production. The flue gas recirculation (FGR) can be highly effective technique for lowering NOx emissions from burners and it's relatively inexpensive to apply. FGR lowers NOx emissions in two ways; the cooler, relatively inert, recirculated flue gases act as heat sink, absorbing heat from the flame and lowering peak flame temperatures and when mixed with the combustion air, recirculated flue gases lower the average oxygen content of the air, starving the NOx-forming reactions for one of the needed ingredients.

Step 2: Eliminate Technically Infeasible Options:

Technology	BACT Evaluation
Selective Catalytic Reduction (SCR) Technically Feasible – **Yes**	Selective Catalytic Reduction (SCR) is technically feasible.
Selective Non-Catalytic Reduction (SNCR) Technically Feasible – **No**	Riverview will operate at a wide range of load levels, with lower levels potentially unable to provide a temperature profile that maintains the range needed for effective control for sufficient residence time to achieve proper control. Some ammonia will be emitted. The combustion units used at Riverview combust a combination of gaseous fuels that are proportionally variable over relatively short time periods and results in short term NOx loading variations. This variability woks against the limited temperature flexibility and difficulty of SNCR in adjusting to short term changes maintaining consistent NOx control during operation of these units. For these reasons, the SNCR is technically infeasible.
Low NOx Burner (LNB) Technically Feasible - **Yes**	LNB/ULNB is technically feasible.
Flue Gas Recirculation (FGR) Technically Feasible – **Yes**	Flue Gas Recirculation (FGR) is technically feasible.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

Control Option	Expected Control Efficiency
LNB/ULNB	40-85%
SCR	70%-90%
FGR	15-50%

Step 1: Identify Potential Control Technologies

For CO, PM/PM10/PM2.5, SO2, VOC and CO2e, the available control technologies are the same as listed under "BACT Analysis Natural gas-fired heaters and boiler" section above.

Step 2: Eliminate Technically Infeasible Options and
Step 3: Rank the Remaining Control Technologies by Control Effectiveness:

For CO, PM/PM10/PM2.5, SO2, VOC and CO2e, there are no add-on control devices that are considered feasible; therefore no ranking is necessary. See "BACT Analysis Natural gas-fired heaters and boiler" above for evaluations of each pollutant.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following tables summarize other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Hydrogen Plant - $PM/PM_{10}/PM_{2.5}$

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*Hydrogen Reformers (EU-7001 and EU-7002)*	*Combustion of natural gas, good combustion practices and energy efficiency*	*PM/PM10: 0.0060 lb/MMBtu PM2.5: 0.0048 lb/MMBtu*	*838.6 (each)*
NatGasoline LLC	TX-0656 PSDTX1340, 107764 (5/6/2014)	reformer	Good combustion practices and fuel selection	PM/PM10: 43.72 tpy (equivalent to 0.006 lb/MMBtu) PM2.5: 32.79 tpy (equivalent to 0.0048 lb/MMBtu)	1552
Flint Hills Resources Pine Bend LLC	MN-0093 03700011-101 (1/13/2017) (draft)	No. 4 hydrogen plant reformer-refining equipment (EQUI 471) (natural gas, refinery fuel gas)	clean fuel, GCP	PM10/PM2.5: 0.0075 lb/MMBtu	744.40
Ticona Polymers	TX-0774 PSDTX1438, GHGPSDTX (11/12/2015)	Reformer	Good combustion practices and firing of high hydrogen process gas, and firing of pipeline quality natural gas	PM10/PM2.5: 5.74 tpy (equivalent to 0.0048 lb/MMBtu)	1190
Although the process is the same, this source is in SIC code 2869 and may not establish BACT for the proposed source.					
Sasol Chemicals (USA) LLC	LA-0289 PSD-LA-778 (5/23/2014) (GTL unit)	Furnaces (EQT 964 & 965) (process gas)	gaseous fuel, GCP	PM10/PM2.5: 2.94 lb/hr 10.61 tpy 0.0075 lb/MMBtu	390.10
The GTL project was reportedly cancelled in November 2017, therefore this entry is not considered to represent BACT for the proposed source.					
Air Products and Chemicals, Inc.	LA-0264 PSD-LA-750 (M1) (9/4/2012)	reformer - Hydrogen Plant	Proper equipment designs, good combustion practices, and gaseous fuel	PM/PM10/PM2.5: 11.24 lb/hr 0.0075 lb/MMBtu	1320
Although the process is the same, this source is in SIC code 2813 and may not establish BACT for the proposed source.					
BP Products North America Inc	OH-0329 P0103694 (8/7/2009)	reformer heater	no add on controls were reasonably cost effective	PM10: 3.9 lb/hr 16.94 tpy 7.6 lb/MMBtu AP-42 factor *(sic)*	519.00

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hyd. reformer furnace flue gas vent	Proper design, operation, and good engineering practices	PM10: 0.0075 lb/MMBtu	1412.5
Air Products	TX-0526 NA 63, 39693 (8/18/2006)	reformer furnace stack - Hydrogen	SCR	PM10: 16.7 lb/hr 63.0 tpy (0.0075 lb/MMBtu)	1373
Although the process is the same, this source is in SIC code 4931 and may not establish BACT for the proposed source.					
Arizona Clean Fuels Yuma, LLC	AZ-0046 1001205 (4/14/2005)	Hyd. Reformer heater	None	PM10: 0.0075 lb/MMBtu	1435
Source may not have been constructed under this permit, therefore this citation is not considered representative of BACT.					

Hydrogen Plant - SO_2

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*Hydrogen Reformers (EU-7001 and EU-7002)*	*Use of low sulfur gas, good combustion practices and energy efficiency*	*0.005 gr S/scf in fuel gas*	*838.6 (each)*
The source has proposed a limit of 0.005 gr S/scf in fuel gas, this is determined to be BACT.					
Sasol Chemicals (USA) LLC	LA-0289 PSD-LA-778 (5/23/2014) (GTL unit)	Furnaces (EQT 964 & 965) (process gas)	use of gaseous fuel with a sulfur content of no more than 0.005 gr/scf (ann avg)	23.21 lb/hr max (ea) 2.09 tpy annual (ea)	390.1
The GTL project was reportedly cancelled in November 2017, therefore this entry is not considered to represent BACT for the proposed source.					
Diamond Shamrock Refining LP	TX-0580 92929 HAP63 (12/30/2010)	Hydrogen production unit furnace (refinery gas (PSA purge gas) w/ natural gas)		sulfur content of the fuel limited to 5 gr/100 dscf (ann avg)	355.65
BP Products North America Inc	OH-0329 P0103694 (8/7/2009)	reformer heater	none	15.52 lb/hr 38.00 tpy 20 ppmv dry at 0% excess air	519.00
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	hydrogen reformer furnace flue gas vent (48-08)	use of low sulfur fuel gas	25 ppmv (as H_2S)	1412.5
Air Products	TX-0526 NA 63, 39693 (8/18/2006)	reformer furnace stack - Hydrogen	SO_2 limit based on 45 ppmv total sulfur in fuel gas	7.3 lb/hr (28.0 tpy)	1373
Although the process is the same, this source is in SIC code 4931 and may not establish BACT for the proposed source.					
Arizona Clean Fuels Yuma, LLC	AZ-0046 1001205 (4/14/2005)	Hyd. Reformer heater	None	S (as H_2S) limited to 35 ppmv	1435
Source may not have been constructed under this permit, therefore this citation is not considered representative of BACT.					

Hydrogen Plant - NOx

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*Hydrogen Reformers (EU-7001 and EU-7002)*	*SCR with low NOx burners*	*0.0065 lb/MMBtu*	*838.6 (each)*

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Air Liquide Large Industries U.S. LP	TX-0738 87575, N116 (2/19/2010)	reformer	SCR	0.0065 lb/MMBtu (annual) 0.015 lb/MMBtu (24-hr) NH3 slip 10 ppmvd@15% O_2	1041
Although this source is in SIC code 2813, not 2911 like the proposed source, the NOx limitation of 0.0065 lb/MMBtu is the most stringent; therefore it has been determined to be BACT because of the similarity of the processes.					
Citgo Petroleum Corp	LA-0326 PSD-LA-222(M-2) (11/7/2017)	3(XXIII)2 C-reformer B-503, B-504, B-505 furnace (refinery fuel gas/reformer hydrogen)	GCP w/ continuous O2 monitor	83.13 lb/hr 0.095 lb/MMBtu (1-hr block avg)	875.00
		3(XXIII)1 C-reformer B-501, B-502, B-506 furnaces		47.12 lb/hr 0.19 lb/MMBtu (1-hr block avg)	248.00
Ticona Polymers	TX-0774 PSDTX1438, GHGPSDTX (11/12/2015)	Reformer	SCR	0.01 lb/MMBtu (12-mo avg.) 0.015 lb/MMBtu (24-mo avg.)	
Although the process is the same, this source is in SIC code 2869 and may not establish BACT for the proposed source.					
Sasol Chemicals (USA) LLC	LA-0289 PSD-LA-778 (5/23/2014) (GTL unit)	Furnaces (EQT 964 & 965) (process gas)	ULNB, SCR	19.73 lb/hr 14.24 tpy 0.01lb/MMBtu (30-day avg)	390.10
The GTL project was reportedly cancelled in November 2017, therefore this entry is not considered to represent BACT for the proposed source.					
NatGasoline LLC	TX-0657 PSDTX1340, 107764 (5/6/2014)	reformer	SCR	59.42 tpy (0.01 lb/MMBtu)	1552
Air Products and Chemicals, Inc.	LA-0264 PSD-LA-750 (M1) (9/4/2012)	reformer - Hydrogen Plant	ULNB and SCR	48.74 lb/hr 0.015 lb/MMBtu	1320
Although the process is the same, this source is in SIC code 2813 and may not establish BACT for the proposed source.					
Diamond Shamrock Refining LP	TX-0580 92929 HAP63 (12/30/2010)	Hydrogen production unit furnace (refinery gas (PSA purge gas) w/ natural gas)	LNB + SCR	0.0150 lb/MMBtu (hourly max) 0.0100 lb/MMBtu (ann avg) ammonia slip <10ppmv at 3% O2	355.65
Air Liquide Large Industries U.S. LP	TX-0591 N116 (2/19/2010)	Reformer - hydrogen production	low NOx-burner and SCR	0.0065 lb/MMBtu (annual) 0.015 lb/MMBtu (24-hr) at 3% O_2	876.6
Although the process is the same, this source is in SIC code 2813 and may not establish BACT for the proposed source.					
BP Products North America Inc	OH-0329 P0103694 (8/7/2009)	reformer heater	none	23.40 lb/hr 79.56 tpy 40 ppmvd @ 0% excess air (24 hr)	519
Air Products	TX-0526 NA 63, 39693 (8/18/2006)	reformer furnace stack - Hydrogen	SCR	81.0 lb/hr 87.0 tpy 90% CE	1373
Although the process is the same, this source is in SIC code 4931 and may not establish BACT for the proposed source.					
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	hydrogen reformer furnace flue gas vent (48-08)	SCR (voluntary) and ULNB	0.0125 lb/MMBtu	1412.5

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Arizona Clean Fuels Yuma, LLC	AZ-0046 1001205 (4/14/2005)	Hyd. Reformer heater	SCR and low Nox burners	0.0125 lb/MMBtu Ammonia: 5 ppmvd	1435
Source may not have been constructed under this permit, therefore this citation is not considered representative of BACT.					

Hydrogen Plant - VOC

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*Hydrogen Reformers (EU-7001 and EU-7002)*	*Combustion of natural gas, good combustion practices and energy efficiency*	*0.0015 lb/MMBtu*	*838.6 (each)*
NatGasoline LLC	TX-0657 PSDTX1340, 107764 (5/6/2014)	reformer	Good combustion practices	5 ppm 10.16 tpy (equivalent to 0.0015 lb/MMBtu)	1552
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hyd. reformer furnace flue gas vent	Proper design, operation, and good engineering practices	0.0015 lb/MMBtu	1412.5
Ticona Polymers	TX-0774 PSDTX1438, GHGPSDTX (11/12/2015)	Reformer	Good combustion practices and firing of high hydrogen process gas, and firing of pipeline quality natural gas	26.27 tpy	
Although the process is the same, this source is in SIC code 2869 and may not establish BACT for the proposed source.					
Sasol Chemicals (USA) LLC	LA-0289 PSD-LA-778 (5/23/2014) (GTL unit)	Furnaces (EQT 964 & 965) (process gas)	GCP, subpart 5D tuneups	2.13 lb/hr 7.68 tpy 0.0054 lb/MMBtu	390.10
Project was reportedly cancelled in November 2017, therefore this source is not considered representative of BACT for the proposed source.					
BP Products North America Inc	OH-0329 P0103694 (8/7/2009)	reformer heater	none	2.80 lb/hr 12.28 tpy 5.50 lb/MMCF AP-42 factor	519
Air Products	TX-0526 NA 63, 39693 (8/18/2006)	reformer furnace stack - Hydrogen	-	3.6 lb/hr (14.0 tpy)	1373
Although the process is the same, this source is in SIC code 4931 and may not establish BACT for the proposed source.					

Hydrogen Plant - CO

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*Hydrogen Reformers (EU-7001 and EU-7002)*	*Combustion of natural gas, good combustion practices and energy efficiency*	*CO: 0.02 lb/MMBtu*	*838.6 (each)*
The source has proposed a limit of 0.020 lb.MMBtu, equivalent to 25 ppmvd, which is more restrictive than other sources. Therefore this has been determined to be BACT.					
Ticona Polymers	TX-0774 PSDTX1438, GHGPSDTX (11/12/2015)	Reformer	Flare (SSM)	CO: 50 ppmvd@ 3% O2	
Although the process is the same, this source is in SIC code 2869 and may not establish BACT for the proposed source.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Sasol Chemicals (USA) LLC	LA-0289 PSD-LA-778 (5/23/2014) (GTL unit)	Furnaces (EQT 964 & 965) (process gas)	GCP, subpart 5D tuneups	CO: 13.81 lb/hr 49.83 tpy 0.035 lb/MMBtu	390.10
Project was reportedly cancelled in November 2017, therefore this source is not considered representative of BACT for the proposed source.					
NatGasoline LLC	TX-0656 PSDTX1340, 107764 (5/6/2014)	reformer	Good combustion practices	CO: 50 ppm 177.4 tpy	1552
Diamond Shamrock Refining LP	TX-0580 92929 HAP63 (12/30/2010)	Hydrogen production unit furnace (refinery gas (PSA purge gas) w/ natural gas)		CO: 100 ppmv @ 3% O2 (max) 50 ppmv @3% O2 (ann avg)	355.65
BP Products North America Inc	OH-0329 P0103694 (8/7/2009)	reformer heater	cites 40 CFR 63, subpart DDDDD as case-by-case MACT	CO: 18.6 lb/hr (equivalent to 50 ppm)	519
Marathon Petroleum	LA-0211 PSD-LA-719 (12/27/2006)	Hyd. reformer furnace flue gas vent	Proper design, operation, and good engineering practices	CO: 0.04 lb/MMBtu	1412.5
Arizona Clean Fuels Yuma, LLC	AZ-0046 1001205 (4/14/2005)	Hyd. Reformer heater	None	CO: 0.01 lb/MMBtu	1435
Source may not have been constructed under this permit, therefore this citation is not considered representative of BACT.					

Hydrogen Plant - CO_2e

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Riverview Energy	*Proposed*	*Hydrogen Plant 1 and Hydrogen Plant 2 (EU-7001 & EU-7002)*	*Combustion of natural gas, good combustion practices and energy efficiency*	*CO2e: 987,271 tons/yr (ea)*	*838.6 (each)*
Dakota Prairie Refining	ND-0031 PTC12090 (2/21/2013)	Hydrogen plant heater	Combustion of clean fuels and energy efficiency	CO2e: 12587 tpy	
		Hydrogen plant process CO2e emissions	none	CO2e: 21094 tpy	
CO2e: Combustion of clean fuels and energy efficiency is the most stringent; therefore it has been determined to be BACT.					
Flint Hills Resources Pine Bend LLC	MN-0093 03700011-101 (1/13/2017) (draft)	No. 4 hydrogen plant reformer-refining equipment (EQUI 471) (natural gas, refinery fuel gas)	clean fuel, GCP	CO2e: 771,156 tpy 365°F stack temp (365-day avg)	740.00
Ticona Polymers	TX-0774 PSDTX1438, GHGPSDTX (11/12/2015)	Reformer	Good combustion practices and firing of high hydrogen process gas, and firing of pipeline quality natural gas, heat integration and best management practices	CO2e: 533629 tpy	
Although the process is the same, this source is in SIC code 2869 and may not establish BACT for the proposed source.					
DE City Refining	DE-0025 APC-2015/0058-C (7/13/2015)	Steam-Methane Reformer with Pressure Swing Adsorption System	None	CO2e: 33.2 tons CO2/MMDscf H2	

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Rating (MMBtu/hr)
Sasol Chemicals (USA) LLC	LA-0289 PSD-LA-778 (5/23/2014) (GTL unit)	Furnaces (EQT 964 & 965) (process gas)	natural gas feedstock, GCP	CO2e: 338,362 tpy	390.10
Project was reportedly cancelled in November 2017, therefore this source is not considered representative of BACT for the proposed source.					
Wynnewood Refinery Co LLC	OK-0160 2007-026-C(M-5) (1/7/2014)	H2 reformer (natural gas)	energy efficiency	CO2e: 120280 lb CO2e/MMscf NG feed	126.00
Phillips 66 Co.	LA-0263 PSD-LA-760 (7/25/2012)	Steam methane reformer (2291-SMR, EQT 0196) (refinery fuel gas)	GCP, PSA H2 purification	CO2e: 183,784 t/yr 0.05 lb/scf prdn (12-mo avg)	216.00

Hydrogen Plant Deaerators

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Hydrogen Plant Deaerators (EU-7003 & EU-7004)*	*None*	*VOC: 3.20 lb/hr CO: 1.06 lb/hr CO2e: 1,080 tons/yr (ea)*	*838.6 (each)*
VOC, CO, and CO_2e limits proposed by the source as BACT.					
Marathon Petroleum - Garyville Refinery	LA-0211 PSD-LA-719 (12/17/2006)	Hydrogen Plant Deaerator vent	None	VOC and CO: No limits	3125 lb/hr
Hunt Refining	AL-0242 X063 through X072 (5/20/2008)	Hydrogen plant degassifier	None (no controls are considered economically feasible)	None	-

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

(a) The units shall burn only gaseous fuels.

(b) PM, PM_{10}, and $PM_{2.5}$ emissions from each reformer shall not exceed:

Emission Limitations[1]	
Pollutant	**lb/MMBtu**
PM	0.006
PM_{10}*	0.006
$PM_{2.5}$*	0.0048

Notes:
1. *PM shall include only filterable PM. PM_{10} and $PM_{2.5}$ shall include filterable and condensable.*

(c) Sulfur content of the fuel gas delivered to each reformer shall not exceed 0.005 gr/scf.

(d) The units shall use selective catalytic reduction (SCR) with low-NOx burners for NOx control.

(e) NOx emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu**
NOx	0.0065

(f) VOC emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu[1]**
VOC	0.0015

Notes:
1. 1-hr average

(g) CO emissions from each reformer shall not exceed:

Emission Limitations	
Pollutant	**lb/MMBtu**
CO	0.020

(h) The CO_2e emissions from Block 7000 hydrogen production operations shall not exceed the values shown in the table below per twelve (12) consecutive month period, with compliance determined at the end of each month.

Emission Limitations	
Unit ID	**CO_2e Limit (tons)**
EU-7001	987,271
EU-7002	987,271
EU-7003	1,080
EU-7004	1,080

(h) VOC emissions from the hydrogen plant deaerators (EU-7003 and EU-7004) shall not exceed 3.20 b/hr, each.

(i) CO emissions from the hydrogen plant deaerators (EU-7003 and EU-7004) shall not exceed 1.06 lb/hr, each.

BACT Analysis
Wastewater Treatment

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following control technologies for control of VOC emissions from wastewater treatment processes:

(a) VOC destruction methods
(b) VOC removal methods
(c) Wastewater treatment process design

Step 2: Eliminate Technically Infeasible Options

(a) VOC destruction methods
VOC destruction processes, e.g., incineration, are not techinically feasible for wastewater streams containing minor amounts of organic compounds. The fuel value of the VOC content is insufficient to support vaporization of the water phase without very substantial use of supplemental fuel. Application of destruction technology to a wastewater stream also requires entirely different unit construction from typical air pollution control devices, i.e., a liquid injection incinerator rather than a flare.

(b) VOC removal
Certain removal processes, such as activated carbon adsorption, are applicable to removal of contaminants from water streams. However, these are generally applied as point-of-use systems for removing trace contaminants from clean streams like drinking water. Oily contaminants and unpredictable suspended solids loading cause plugging in activated carbon systems so adsorption processes are not feasible for wastewater treatment at the proposed source.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ has ranked the control technologies in order of effectiveness as follows:

(a) Conformance with the requirements of 40 CFR 60, Subpart QQQ; 40 CFR 61, Subpart FF; and 40 CFR 63, Subpart CC; including but not limited to covered oil-water separators, water seal drains, and closed vent systems. (estimated 96% control based on AP-42 Section 5.1)

The applicant proposed a wastewater collection and treatment system compliant with 40 CFR 60, Subpart QQQ which is top BACT. Therefore, a ranking is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Wastewater treatment*	-	*VOC emissions from the wastewater treatment vent (EU-8001), oily water sump (EU-8002), and MH1 (EU-8003) shall not exceed 20 ppmvd, each*	NA
Castleton Commodities International Corpus Christi	TX-0756 116072 & PSDTX1388 (6/19/2015)	Wastewater treatment plant	Overall system to achieve 90% of VOC from treated wastewater. Oil/water separator is enclosed and routed to a carbon adsorption system (CAS). Process drains to be equipped with a water seal. Wastewater sewers will be enclosed. Aerobic digesters will be enclosed and directed to a CAS.	4.56 lb/hr 9.04 tpy 90% overall control	-

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Magellan Processing LP	TX-0731 118270 & PSDTX1398 (4/10/2015)	Petroleum refining wastewater and wastewater treatment	Process wastewater shall be immediately directed to a covered system. All lift stations, manholes, junction boxes, conveyances, and any other wastewater facilities shall be covered and all emissions routed to a vapor combustor with a guaranteed DRE of 99% for control.	0.4 tpy	-
Specification of DRE is considered as specific for the emissions control device (i.e., vapor combustor), not as an achievable overall control efficiency for VOC emissions from wastewater collection and treatment processes.					
Valero Refining New Orleans LLC	LA-0213 PSD-LA-619 (M5) (11/17/2009)	Wastewater collection & treament: refinery	WW (EQT0255): comply with LA refinery MACT WWTU (EQT0359): comply with 40 CFR 61 subpart FF CRUIDS *(sic)* (EQT369): comply with 40 CFR 63 subparts F & G	-	-
Sunoco Inc	OH-0308 04-01447 (2/29/2009)	wastewater streams	-	91.19 tpy	-
This entry is identified as MACT, therefore it is not considered to establish BACT for the proposed source.					
Conoco Phillips	IL-0103 06050052 (8/5/2008)	wastewater treatment plant	Good air pollution control practices	-	-
This entry is identified as LAER, therefore it is not considered to establish BACT for the proposed source.					

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM, OAQ has established the following as VOC BACT for wastewater collection and treatment operations:

(a) VOC emissions from the wastewater treatment vent (EU-8001), oily water sump (EU-8002), and manhole no. 1 (EU-8003) shall not exceed 20 parts per million by volume (dry) (ppmvd), each.

BACT Analysis
VOC Leaks

Step 1: Identify Potential Control Technologies

IDEM, OAQ has identified the following control technologies for VOC control from fugitive emission sources:

(a) Leak Detection and Repair Program (LDAR)
(b) No Control Option

Step 2: Eliminate Technically Infeasible Options

(a) Leak Detection and Repair Program (LDAR)
A leak detection and control program (LDAR) is a systematic method of finding and eliminating fugitive emissions from leaking pumps, valves, compressors, pipe fitting, sampling connections, etc. LDAR is a work practice that assists sources identify leaking equipment so that emissions can be reduced though systematic repair or replacement. The key to the effectiveness of fugitive emission control is the regularly scheduled inspections and a defined

repair/replacement schedule. The use of an LDAR program is a technically feasible control option for the fugitive VOC emissions.

(b) No Control Option
It is possible that fugitive emissions from a source are so small that the time and cost required to establish and implement an LDAR program are not cost effective. Fugitive VOC emissions were estimated by the source at 14.39 tons per year. The use of no control is a technically feasible control option for the fugitive VOC emissions.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

IDEM, OAQ has ranked the control technologies in order of effectiveness as follows:

(a) LDAR (98% control)
(b) No Control (0% control)

The applicant proposed an LDAR program which is top BACT. Therefore, a ranking is not required.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following table summarizes other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Riverview Energy	*Proposed*	*Fugitive VOC*	*LDAR Program per 40 CFR 60, Subpart GGGa*	*Block 2000: 151.18 tpy Block 4000: 25.04 tpy*	NA
Gravity Midstream Corpus Christi LLC	9342A, 9343A, PSDTX963M 1 (10/31/2016)	equipment leaks	quarterly monitoring, 40 CFR 60, subparts GGG & GGGa	8.72 tpy	-
Phillips 66 Co	LA-0283 PSD-LA-696 (M-3) (8/14/2015)	unit fugitives for low sulfur gasoline unit (294-FF, FUG 0004)	LDR: Louisiana MACT determination for refinery equipment leaks (fugitive emission sources) dated 7/26/1994	15.43 lb/hr 67.59 tpy	-
Motiva Enterprises LLC	TX-0759 6056, PSDTX1062 M2, GHG121 (7/31/2015)	hydrocracking and hydrotreating fugitive components	enhanced LDAR program, 500 ppmv leak definition	147.66 tpy	-
Midwest Fertilizer Corporation	IN-0173 T129-33576-00059 (6/4/2014)	fugitve emissions (F-1)	LDAR Program 40 CFR 60, Subpart VVa	None	NA
Sasol Chemicals (USA) LLC	LA-0291 PSD-LA-778 (5/23/2014) (GTL unit)	GTL unit fugitive emissions (FUG 15)	LDAR program per 40 CFR 63, subpart FFFF	none	89.13 tpy
GTL project was reportedly cancelled in November 2017.					
Ohio Valley Resources	IN-0179 T147-32322-00062 (9/25/2013)	process fugitive VOC	LDAR Program 40 CFR 60, Subpart VVa	-	NA
The permit for this source was revoked.					

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT	Throughput (ton/yr)
Southeast Renewable Fuels	FL-0322 PSD-FL-412, 0510032-001-AC (12/23/2010)	Fugitives FUG0030	LDAR Program 40 CFR 60, Subpart VVa	6.52 tpy	NA
Valero, Hydrogen Plant	LA-0245 PSD-LA-750 (12/15/2010)	hydrogen plant fugitives (FUG0030)	LDAR pgm that meets LA refinery MACT with consent decree enhancements (7/26/1994)	23.74 tpy	NA
Sabina Petrochemicals	TX-0575 N018M1 (8/20/2010)	ALKFUG, BDEFUG, UTILFUG	state LAER LDAR program	9.01 tpy	NA
Requirements for this source are LAER and therefore not applicable in determining BACT for the proposed source.					
Highlands Ethanol Facility	FL-0318 PSD-FL-406, 0550061-001-AC (12/10/2009)	Fugitive VOC Emissions	LDAR Program 40 CFR 60, Subpart VVa	19.60 tpy	NA
Conoco Phillips	LA-0197 PSD-LA-696 (M1) (7/21/2009)	unit fugitives	LDAR pgm that meets LA refinery MACT with consent decree enhancements (7/26/1994)	57.89 tpy	NA
Ohio River Clean Fuels LLC	OH-0317 02-22896 (11/20/2008)	equipment leaks	use of leakless/sealless or low-emission pumps, valves, and compressors. LDAR program, 40 CFR 60, subpart GGa	1.70 tpy	-
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.					
Arizona Clean Fuels Yuma, LLC	AZ-0046 1001205 (4/14/2005)	equipment leaks	LDAR program, 40 CFR 63, subpart H	-	-

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT) and 326 IAC 8-1-6 (New Facilities; General Reduction Requirements), IDEM, OAQ has established the following as VOC BACT for fugitive VOC emissions:

(a) Fugitive VOC emissions shall be controlled by a Leak Detection and Repair (LDAR) program. The leak detection and repair program specified in 40 CFR 60, Subpart GGGa shall serve as BACT for VOC fugitive emissions.

(1) Fugitive VOC emissions from Block 2000 VEBA Combi Cracker operations shall not exceed 151.18 tons per twelve (12) consecutive month period.

(2) Fugitive VOC emissions from Block 4000 offsites operations shall not exceed 25.04 tons per twelve (12) consecutive month period.

Particulate (PM, PM_{10} and $PM_{2.5}$) BACT Analysis
Roads

Step 1: Identify Potential Control Technologies

Emissions of particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to ten (10) micrometers (PM_{10}) and $PM_{2.5}$ from fugitive sources are generally controlled with measures to prevent the emissions from occurring. Generally, fugitive PM, PM_{10} and $PM_{2.5}$ emissions from roadways are controlled through one of the following mechanisms:

(1) Paving of Roadways
(2) Wet Suppression or Chemical suppression
(3) Good Housekeeping (cleanup spilled material)

Add-on particulate control devices such as cyclones, scrubbers, baghouses or ESP's are not possible alternatives because the roadways cannot be enclosed and vented to a point source control device.

Step 2: Eliminate Technically Infeasible Options

Wet Suppression or Chemical suppression:
Wet suppression systems use liquid sprays or foam to suppress the formation of airborne dust. The primary control mechanisms are those that prevent emissions through agglomerate formation by combining small dust particles with larger aggregate or with liquid droplets. The key factors that affect the degree of agglomeration and, hence, the performance of the system are the coverage of the material by the liquid and the ability of the liquid to wet small particles. There are two types of wet suppression systems: liquid sprays which use water or water/surfactant mixtures as the wetting agent and systems which supply foams as the wetting agent. Wet suppression systems typically achieve PM control efficiencies of greater than 85%.

Based on the information reviewed for this BACT determination, IDEM, OAQ has determined that the use of a Wet Suppression or Chemical suppression is a technically feasible option for the roads at this source.

Paving Roadways and Good Housekeeping
Paving all haul roads and prompt cleanup of any spilled or eroded materials are effective at minimizing dust emissions from vehicle traffic.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

(1) Paving haul roads reduces vehicle dust emissions versus unpaved surfaces and is feasible.

(2) Wet or chemical suppression (frequent use of water or chemical surfactants) can significantly reduce airborne dust emissions from both paved and unpaved roadways.

(3) Particulate emission from paved roadways can also be minimized with good housekeeping, i.e. cleaning up spills of solid material or dirt eroded onto the road surfaces.

Step 4: Evaluate the Most Effective Controls and Document the Results

The following tables summarize other BACT determinations at similar sources or for similar processes that were identified in the EPA's RACT/BACT/LAER Clearinghouse (RBLC):

Paved Roadways and Parking areas

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT
Riverview Energy	*Proposed*	*Paved Roads*	*All roads shall be paved*	*VE: 0% except for 1 min. in any 1-hr period* *Development, maintenance, and implementation of a fugitive dust control plan.*
V&M Star	OH-0344 P0107088 (1/27/2011)	Paved Roads	watering, sweeping, chemical stabilization, or suppressants applied at sufficient frequencies	Paved & Unpaved roads PM: 38.3 tpy PM10: 7.7 tpy VE: 0% except for 1 min. every 60
Sun Coke Energy	OH-0332 P0104768 (5/20/2010)	Paved Roads	Watering	PM: 1.08 tpy PM10: 0.21 tpy PM2.5: 0.05 tpy fugitive VE: No VE except for any 1 min in any 60 min.
New Steel International, Inc.	OH-0315 07-00587 (5/6/2008)	Paved Roads	wet suppressants, watering, speed reduction and vacuuming or sweeping	PM: 153.4 tpy PM2.5: 29.9 tpy VE: 0% except for 1 min. every 60
Paving roads with watering, sweeping, chemical stabilization, or suppressants applied at sufficient frequencies is the most stringent. Therefore, this has been determined to be BACT. VE: 0% except for 1 min. every 60 is the most stringent. Therefore, this has been determined to be BACT.				
Midwest Fertilizer Corp.	IN-0173 T129-33576-00059 (6/4/2014)	Paved Roads	paving all haul roads, daily sweeping with wet suppression and prompt cleanup of any spilled materials	PM/PM10/PM2.5: 90 % control
90% control of fugitives is the most restrictive and is determined to be BACT.				
Ohio Valley Resources, LLC	IN-0179 T147-32322-00062 (9/25/2013)	Paved Roads	paving all plant haul roads, wet or chemical suppression and prompt cleanup of any spilled materials	PM/PM10/PM2.5: 90 % control
Note: This permit has been revoked and it is not clear whether the limits were tested, therefore this source is not considered in determining BACT for the proposed source.				
Indiana Gasification, LLC	IN-0166 T147-30464-00060 (6/27/2012)	Paved Roads	paving all plant haul roads, wet or chemical suppression and prompt cleanup of any spilled materials	PM/PM10/PM2.5: 90 % control
Note: This permit has been revoked and it is not clear whether the limits were tested, therefore this source is not considered in determining BACT for the proposed source.				
Rumpke Sanitary Landfill	OH-0330 07-00574 (12/30/2008)	Paved Roads	water flushing, sweeping	PM: 58 tpy (paved & unpaved) PM10: 15.1 tpy (paved & unpaved) VE: 5% opacity as 3-min avg.

Facility - County, State	RBLC ID / Permit # (Issuance Date)	Process	Control	BACT
Ohio River Clean Fuels, LLC	OH-0317 02-22896 (11/20/2008)	Paved Roads	Reduce speed limit, sweeping, watering and good housekeeping	PM: 79.0 tpy PM10: 15.39 tpy VE: No VE except for any 1 min in any 60 min.
Note: Source was not constructed; therefore, it has not been demonstrated that this limit can be complied with. Therefore, this was not considered BACT.				
Argos USA	SC-0132 0900-0004-EF-R2 (12/14/2007)	Paved Roads	Best mgmt practices consisting of sweeping and/or water flushing	PM
Entergy Louisiana, LLC	LA-0221 PSD-LA-720 (11/30/2007)	Paved Roads	Newly constructed roads will be paved	PM10: 4.07 lb/hr (17.2 tpy)
Mesabi Nugget	MN-0061 13700318-001 (6/26/2005)	Paved Roads	Fugitive dust control plan	VE: 5% opacity
Martco Limited Partnership	LA-0203 PSD-LA-710 (6/13/2005)	Paved Roads	Limited access	PM10: 2.6 lb/hr
Louisiana Generating, LLC	LA-0223 PSD-LA-660M1 (1/8/2008)	Paved Roads	Pave all roads	PM10: 1.21 lb/hr 3.54 tpy

Step 5: Select BACT

Pursuant to 326 IAC 2-2-3 (PSD BACT), IDEM has established the following BACT:

BACT shall be:

(a) The Best Available Control Technology (PSD BACT) for PM, PM_{10}, and $PM_{2.5}$ for the paved roads shall be the development, maintenance, and implementation of a fugitive dust control plan, which shall include but not be limited to vacuum sweeping and water flushing as necessary and the implementation of a speed reduction plan.

(b) Visible emissions from truck traffic on plant roads shall not exceed one (1) minute in any one (1) hour period.